University of Washington
Department of Civil and Environmental Engineering

COMPLEXITY AS A MEASURE OF SIMULATION MODEL APPROPRIATENESS: COLUMBIA RIVER CONFLICT AS A CASE STUDY

Julia L. Cohan
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Water Resources Series
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ABSTRACT

This report addresses the problem of simulation model complexity in water resource systems planning. The level of complexity incorporated into a model is shown to be a primary determinant of the value of the model for use in decison making. This is illustrated with a review of models being applied for management of the conflict between fish production and hydropower production in the Columbia River Basin. A two-part test is proposed for determining whether a model has incorporated an appropriate degree of complexity and is applied to the models reviewed. It is concluded that the models currently used to generate trade-offs between conflicting uses of water in the basin are too complex for conflict resolution.

To demonstrate the value of a simplified model, which would be more suitable for generating trade-offs, and to identify methods by which variables in existing models can be aggregated, an equivalent composite reservoir was modeled. Two versions of the model were run using the 40-year record of streamflows currently used in planning; one incorporating the Water Budget into annual planning and operations, and one without the Water Budget. By comparing the results of these two studies with those performed by the Corps of Engineers for the Instream Flow Work Group in 1982, it was shown for both scenarios that the simplified model (CRISP) accurately estimated average annual energy, as well as average energy from July to December and January to June.

The model was modified for use with synthetic streamflow data, and a series of Monte Carlo simulations were run using a large number of 50-year synthetic flow sequences. The representation of streamflows as stochastic events constituted an improvement on the approach of existing models using a historical record of flows. In addition, it allowed estimation of sensitivity of indexes of system performance to critical input parameters over a broad range of flows. The parameters investigated were the volume of the Water Budget, the size of the standard errors of forecasted inflows, and the percent hedge. The results of the Monte Carlo simulations indicated that the Water Budget has modest impacts on system refill and average annual generation. However, it was shown that most indices of system performance are more sensitive to the size of the standard errors of the forecasted inflows and the hedging factor than they are to the volume of the Water Budget. Therefore, it was suggested that future modeling efforts give attention to the effect of improved forecasting ability on system characteristics.

Finally, by comparing the processing complexity and amount of computer resources used by the complex hydroregulator models and the one reservoir model, it was concluded that a simplified model would be a valuable addition to the collection of models currently used to investigate the conflict on the Columbia River.

KEY WORDS: Model Complexity, Monte Carlo Simulation, Hydropower Production, Fish Production, Conflict Resolution

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CHAPTER 1

Introduction

Computer simulation models are valuable tools in the evaluation of trade-offs between conflicting uses of a water resource. A model provides decision makers with the opportunity to analyze the effects of alternative solutions to complex problems efficiently and cost effectively. The value of a particular simulation model is influenced by its basic characteristics, including evolutionary potential, ease of use, portability, and flexibility. In addition, the level of complexity of a model may be a primary determinant of the value of the model for decision making. One of the goals of this research is to determine the effect of model complexity in the context of a particular water resource conflict.

The case study chosen is the conflict between fish and hydropower production on the Columbia River. The transformation of the river from a free-flowing river to a series of dams and reservoirs has been identified as a major factor in the decline of the anadromous fishery of the basin, an important natural resource for the region (Columbia River Fisheries Council, 1978). This conflict provides an excellent illustration of the use of simulation models in a decision-making arena. Recently enacted federal legislation includes explicit language mandating the evaluation of trade-offs between fish and hydropower. The Pacific Northwest Electric Power Planning and Conservation Act (PL 96-501) created the Northwest Power Planning Council with the purpose of "establishing objectives for the development and operation of (hydroelectric) projects on the Columbia River and its tributaries in a manner designed to protect, mitigate, and enhance fish and wildlife."

As an aid in the establishment of these objectives, various simulation models have been used by government agencies and private companies involved in management of the river. The U.S. Army Corps of Engineers, the Bonneville Power Administration, and the Washington

State Department of Fisheries maintain computer models capable of evaluating impacts of alternative solutions to the problem. The models vary in their level of complexity, ease of use, flexibility, and portability. As a result, multi-agency participation in the decision-making process is severely hampered, and agencies such as the Washington State Department of Ecology and the National Marine Fisheries Service must rely on other agencies for modeling results which are crucial to their own planning efforts.

The primary goal of this study is to assess the level of complexity incorporated into these models and to recommend appropriate levels of complexity for use in future modeling efforts. This was achieved through a combination of methods. The study began with a review of the systems analysis literature addressing the problem of complexity. Next, a series of interviews was conducted with personnel in the agencies using the models. Insights from the interviews were used to assess the appropriateness of the levels of complexity of existing models. Finally, a simple model capable of quantifying trade-offs between fish and hydropower production was developed. The model was used to determine the minimum level of complexity which would be useful to decision makers in their analysis of the problem.

This report begins with a discussion of the nature of complexity in systems and models. A two-part test is proposed for use in determining whether a model has incorporated an appropriate degree of complexity. Chapter 3 provides an overview of the Columbia River system, the setting of the conflict being modeled. A detailed description of the operation of the system for power production and the resulting problems experienced by the fish is given in Chapter 4. This background is necessary to understand the assumptions behind the models and the degree to which the actual system is being simplified in order to allow efficient models to be made. Chapter 5 reviews models which have been used in the management of the conflict. Indicators of complexity are evaluated for each model and are used to characterize the complexity of the models. A comparison is made between the level of complexity of the different classes of models. Chapter 6 describes the model developed for this study and the results of regulations performed with the model using the 40-year historical record of flows currently used in planning and a large number of synthetic sequences of inflows. The test proposed in Chapter 2 to determine whether a model has incorporated an appropriate degree of complexity is applied to the model in Chapter 7. The result of this test is then used in the recommendation of complexity to incorporate into future models. Appendix A describes the interview process and gives a brief discussion of each interview.

CHAPTER 2

Model Complexity

Complexity is one of several factors influencing the potential usefulness of a computer model. The primary goal of this research is to determine the extent to which the complexity of a model influences its value and to recommend appropriate levels of complexity for the Columbia River management models. Before this can be done, the meaning of complexity as it relates to systems and models must be understood. This chapter addresses the following questions: How is complexity defined in the systems analysis literature? Given several proposed measures of complexity, how can models be compared on the basis of their complexity? How can complex models be simplified? Finally, what degree of complexity in models will be useful to decision makers?

Complexity as a Property

While some researchers claim that the complexity of a model is an intrinsic property of the model, others argue that model complexity is a purely subjective property. Proponents of the former viewpoint have attempted to define model complexity through various quantitative measures of model characteristics. The two most frequently suggested measures of complexity are: 1) the number of variables in the model, and 2) the degree of interaction between these variables. Other commonly suggested measures include the degree to which stochastic processes affect the behavior of the model and the computational problems in describing the variables and their interactions. Those who see complexity as a subjective property believe that the complexity of a model may only be characterized by comparison either with other models of a similar class, or with the system being modeled. Gaines (1977) refers to complexity as an order relation that "gives rise to a trade-off between the degree of approximation and the preference for models," but warns that this ordering is not intrinsic to the particular class of models. Sisson (1974) states that while complexity is an important model characteristic, it can only be evaluated in relation to the complexity of the system being modeled.

Measures of Complexity

Measures of complexity such as the number of elements and the degree of interaction between these elements arise from the perception that "the complexity of a model is related to the difficulty that a modeler has in unravelling its structure to reveal its behavior" (Zeigler, 1976). The assertion that complexity increases with an increasing number of elements is largely accepted by researchers. Measures of the degree of interaction between variables are the subject of several studies. MacKinnon and Wearing (1980) state that "the main contribution of interactions to system complexity is through the causal loops that are a monotonic increasing function of the number of connections. Such loops may involve positive or negative feedback, the coexistence of which may result in unexpected, difficult to trace, and unpredictable behavior."

One indicator of the degree of interaction between variables is the dependence matrix, which is defined as follows: If there are n variables in a model, the dependence matrix has n rows and n columns, with the ijth element being zero or one, depending on whether the ith row variable depends on the jth column variable. A proposed measure of complexity is the rank of this matrix, where the rank is the number of linearly independent equations produced if the matrix is considered to be an array of coefficients (La Porte, 1975).

Although much of the research on complexity has been nonexperimental, there have been simulation experiments conducted that provide insight into measures of complexity. Brewer (1975) built a simple model of an economy and varied its complexity in three ways: increasing the number of variables by spatially disaggregating the economy; increasing the number of interactions between elements by introducing migration between spatial sectors; and increasing uncertainty by introducing a random disturbance in the relationships between the variables. He then calculated the number of indirect structural connections between elements of the model by raising the dependence matrix to the nth power, where n was the time period index, and the number of indirect connections provided an indication of system complexity. He found that extending the model in time resulted in a "staggering number of realized indirect connections" when each of the complicating factors were introduced.

In another experiment focusing on connections between variables, Metlay (1975) investigated possible sources of error that arise when a modeler simplifies a complex system by ignoring critical linkages that may exist, or is unaware of linkages which are present because he has insufficient knowledge of the complexity of the system. The study focuses on the effect of interactions on complexity as indicated by changes in the dependence matrix over time. Metlay evaluated the effects of using various simple models to represent a complex system by computing a matrix which represents the proportion of dependence of the complex system not present in the simple model. He found that in less than 100 time periods, up to 100 percent of the dependencies in the complex system were not represented by the simple models. This demonstrates the danger associated with ignoring interactions between model elements.

Another suggested measure of complexity is the computational resources required for implementation of a model. Zeigler (1976) claims that "the complexity of a model structure is related to the resources required by a computer in generating the model behavior employing instructions based on the model structure," referring to resources such as time and storage space needed to compute a "global state change" in which the values of all variables are updated. Zeigler identifies several quantitative measures of complexity that may be obtained from analysis of a directed graph of the model structure. These measures include: 1) the number of points on the directed graph (each point representing a state variable), 2) the number of lines on the directed graph (each line representing a direct influence of one variable on another), 3) the size of the maximal strong component, and 4) the number of strong components. A strong component is a maximal set such that for every pair of points a,b in the set, there exists a directed path from a to b and from b to a. Therefore, they represent sets of components which are involved in a two-way interaction or feedback. Any two strong components are either unconnected from each other or are involved only in a one-way interaction. In a sequential simulation, these measures would all relate to the amount of time and storage space required by a computer to compute a global transition.

The size of the maximal strong component represents the amount of storage over and above what is required by any simulation strategy to store the present variable values. In a typical simulation strategy, temporary values of all variables are saved while each variable is updated; this strategy requires a number of storage locations equal to twice the number of variables minus one. The number of strong components indicates the number of times in the suggested simulation strategy that the additional storage area is cleared and loaded. Because measures such as these are derived from graph theory, which deals with relationships between a limited number of elements, their practical use is limited by the size of the model.

One last measure of complexity proposed is the number of modes in which it is possible to interact with the system. Rosen (1977) defines a complex system as one in which "we can interact effectively in many different kinds of ways, each requiring a different mode of system description." Interpreted broadly, this definition suggests that the number of modes in which a computer simulation program can be run provides a measure of the complexity of the model, providing each mode represents a different mode of operation of the system.

Developing a Characterization of Model Complexity

Numerous measures of complexity have been proposed in the literature: the number of variables in the model, the degree of interaction between variables, the degree of uncertainty incorporated into the model, and the amount of resources used by a computer in performing the required computations. Although there have been many measures of complexity proposed, there is no universally accepted measure of complexity which can be used to compare the complexity of models. The reasons for this are threefold. First, there is no general agreement on the proper measures of complexity. Although most researchers agree that the number of variables and the degree of interaction provide good indications of complexity, many believe that other model properties such as the degree of uncertainty and the computational requirements are better measures of complexity. In addition, certain quantifying measures have been proposed, but there is no feasible way of making the measurements to determine their value for large models. This problem exists for such measures as number of strong components, size of the maximal strong component, and rank of a dependence matrix. Finally, even if there were agreement on a set of individual measures, there is no method for combining them into a single overall measure of complexity.

The third reason is based on the claim that it is not possible to make trade-offs among the components of complexity. This objection implies that to order models on the basis of their complexity would require showing that one model was more complex than others on the basis of every measure of complexity. McFarland (in La Porte, 1975) states, "If one system has fewer components but greater interdependence and variability than another, it would be difficult or impossible to determine which system is more complex, unless the system with fewer variables is identical to a subsystem of the second system." If this objection is valid, how is it possible to compare the complexity of two different models? An exact answer as to which model is "most complex" may not be found via a comparison of components of complexity such as the number of variables, the degree of interaction between the variables, or the degree of uncertainty incorporated into the models. There do exist indirect indicators of model complexity, however, which are related to the model characteristics previously referred to as components of complexity. Such indicators include the resources used by a computer to execute the model, the size of the model, and the number of modes of operation of the computer program. The resources used by a computer include time and storage space, and the analytic size of the model would best be indicated by the number of executable lines of computer code. While it has been shown that problems of identical size may be solved by computer algorithms requiring vastly different computer resources (Aho et al., 1974), it is beyond the scope of this study to compare the computational efficiency of the algorithms used in the simulation models reviewed here. Therefore, the indicators just mentioned will be used in this study to provide, in conjunction with information on the components of complexity, an indication of the levels of complexity of different classes of models.

The Correct Degree of Complexity

Finding the correct degree of detail or complexity to incorporate into a model is a difficult task. In Brewer (1975), Hubert Blalock describes the problem:

> "The dilemma of the scientist is to select models that are at the same time simple enough to permit him to think with the aid of the model but also sufficiently realistic that the simplifications do not lead to [highly inaccurate] predictions...Put simply, the basic dilemma faced in all sciences is that of how much to oversimplify reality."

A model should be simple enough to be used effectively, but complex enough to be sufficiently realistic. How does a modeler find the correct balance or degree of complexity to incorporate into the model? In a discussion of the use of models in water resources planning, Jackson (1975) addresses the question: "One should try to construct a model that preserves important parameters but should not expend any extra effort or allow any extra complexity in modeling parameters that do not matter." She argues that if a complex model does not produce significantly different physical outputs than a simpler model does, there is no justification for using the more complex model. Put succinctly, "complexity must justify itself through its ability to indicate better decisions than alternative simpler models would" (Jackson, 1975).

The argument against complexity for its own sake stems from problems inherent in large models. Complex models may present problems for the user unfamiliar with the procedures involved in executing the computer program, particularly where ancillary data management programs are necessary. However, even where programs are designed to be user-friendly, complexity presents other problems. In a discussion of the use of synthetic hydrology with water resources yield models, Palmer and Lettenmaier (1983) showed that the cost of executing a yield model using a large number of synthetic sequences is a serious drawback in applying the model to complex systems. Perhaps the biggest problem associated with complex models is that after a certain degree of complexity is reached, the modeler may no longer be able to understand the results or predictions of his own model. Brewer (1975) states a strong case against complex models: "The possibilities for a researcher to understand and manipulate a model decrease rapidly as the analytic size of his formulation increases." This problem frequently gives rise to yet another: a complex model which is not understood even by its developer is likely to be used incorrectly. Another problem is that large models are often difficult to calibrate, particularly where data are limited.

How do models get so complicated in the first place? Shannon (1975) claims that "simple models lead to more complex models, as the researcher analyzes and better understands the problem." This seems to contradict Ackoff and Sasieni's opinion that "the extent to which a phenomenon is understood is inversely proportional to the number of variables required to explain it" (in Shannon, 1975).

Aggregation and Disaggregation

The extent to which variables are aggregated is an important characteristic of a model and a primary determinant of the complexity of the model. When developing a model, often the first steps taken to give a better picture of reality are to add new variables or to disaggregate existing variables. The method of disaggregation is useful in instances where rates of change and variable values differ greatly over some range (spatial or temporal, for instance), or where the aggregated variables provide insufficient detail. However, disaggregation increases both the analytic size of the model and difficulties in the analysis of results. Brewer (1975) suggests that adding "distinct conceptual elements" to provide conceptual detail may be preferable to adding spatial disaggregations which provide spatial detail. He believes that the latter only complicates matters unnecessarily without contributing useful information. In a similar objection, referring to Columbia River water management models, Schultz (1984) suggested that temporal disaggregation may add only "a veneer of sophistication" to a model.

If a model does become too complex for analysis, aggregation of variables is often practiced. It is generally accepted that when a modeler transforms a model structure by common procedures such as aggregating or dropping variables, the resultant model is necessarily simpler than the original. This will be true for measures of complexity such as the number of variables and the number of interactions between variables. However, Zeigler (1976) has shown that for some model structures, measures of complexity such as the size of the maximal strong component and the number of strong components will not necessarily change as a result of aggregation. The case for aggregate models remains strong though; they are generally less expensive to develop, operate more quickly when computerized, and have less extensive data requirements than disaggregated models. The question remains as to how to aggregate to gain the benefits of an efficient model while retaining useful and realistic representations of the system. Gilli and Rossier (1980) have suggested a system of simplifying the description of complex models which may be interpreted as a guide for aggregating variables.

However, this technique relies on a knowledge of advanced graph theory and has limited application.

Usefulness of Complex Models

Given a complex model, how useful will it be to decision makers? A model is useful when it is easily manipulated and the results are understandable and significant to the decision at hand. The model must provide a direct means for sensitivity analysis of the important parameters. This criterion need not necessarily be influenced by the model complexity. The second criterion, that the results are understandable, is directly influenced by model complexity. La Porte (1975) suggests that the limit to any complex development is the ability of individuals to "process information." The third criterion, that the results are significant, should be met by any model that is intended to be used as a prescriptive model. However, there is a tendency when building complex models to report results which are not significant and which do not affect decision criteria.

While there is no accepted overall measure of model complexity, it is possible to characterize the level of complexity of classes of models through certain indirect indicators of complexity. These indicators are determined by the "components" of complexity in a direct but undefinable way. Once the level of complexity of a particular model or class of models has been characterized, the question becomes whether the "correct" level has been reached. This question may be answered in two parts: Is the model useful? Is it the simplest possible model which gives the necessary information on which to base a decision? A model which satisfies the first criterion but not the second can be said to possess an inappropriate degree of complexity for its intended purpose. These criteria will be used throughout this study to determine whether the Columbia River management models reviewed possess appropriate levels of complexity.

CHAPTER 3

The Columbia River System

Computer models used to assist in the management of the Columbia River System provide an excellent setting to illustrate characterizations of complexity. The criteria discussed in Chapter 2 will be applied to these models and appropriate levels of complexity will be determined in the context of the intended purpose of each model. Before the models can be reviewed, however, the nature of the system must be understood, as well as the main concerns of those agencies using the models. This chapter describes the conditions of the river in its natural state and contrasts these with present-day conditions, emphasizing changes in the seasonal streamflow patterns. Those uses of the river which significantly impact regulation of the reservoirs are discussed in detail.

The Columbia River Resource

The Columbia River is a resource of tremendous value to the Pacific Northwest. The third largest river in North America, it runs 1214 miles to the Pacific Ocean, draining an area of 259,000 square miles. Fifteen percent of the drainage area is located in Canada, contributing to the headwaters of the river. The ultimate source of the river is Columbia Lake, high in the Selkirk Mountain Range in Canada. From its source, the Columbia River drops 2650 feet to sea level. Figure 1 shows the course of the river and its major tributaries.

The natural conditions of the Columbia River made it an ideal habitat for many species of fish and wildlife, and early settlers of the region settled along the shores of the river to take advantage of the abundant food sources and transportation routes. Since that time, the population of the region has grown to over 7 million people and the river has been transformed into a series of dams and reservoirs, its flows being regulated on an hourly and seasonal basis for the purposes of electric power production, irrigation, flood

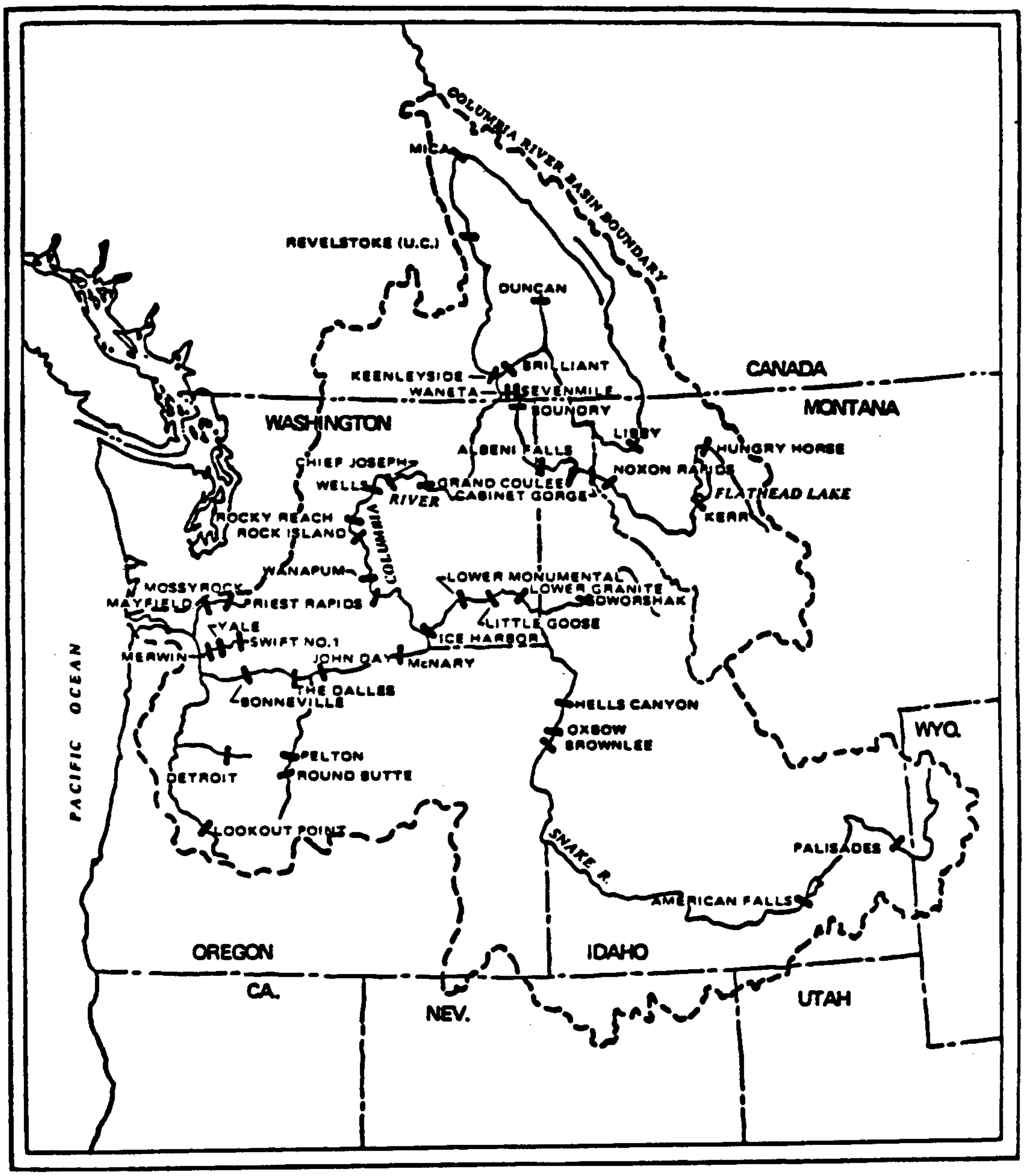

Figure 1. The Columbia River Basin

Source: State of Washington Department of Ecology, 1980.

control, recreation, and most recently, fish production. The unique requirements of each use have resulted in severe conflicts over the uses of water in the basin.

Natural and Regulated Flow Patterns

The natural streamflow pattern of the Columbia River is one of considerable seasonal variation. The lowest flows are in September to March. Flows rise through April and the highest flows of the year occur in May and June. In July and August flows recede. During winter most of the precipitation falls as snow in the mountains; high summer runoff results from the melting snowpack.

The diversion of 14.3 million acre-feet (MAF)/year of water for irrigation and the construction of more than 43 MAF of reservoir storage capacity on the Columbia and lower Snake Rivers have dramatically altered the natural streamflow pattern. The system storage capacity is approximately 40 percent of the annual runoff of the river; regulation made possible by this storage capacity changes the magnitude and timing of the extreme flows. Peaks in streamflows are smoothed by storage capacity. High flows are reduced by filling storage, and low flows are increased by releasing from storage. Figure 2 shows the effect of reservoir regulation on the natural streamflow pattern.

The Depletions Task Force of the Columbia River Water Management Group determines flow rates which would have occurred in the absence of regulation. Such flows are termed "modified flows" and are determined by adjusting regulated flows for storage changes in all reservoirs above a given gaging site and adjusting for irrigation depletions corresponding to a given level (year) of development (Columbia River Water Management Group, 1982). The modified flows are updated monthly at the Columbia River at Grand Coulee Dam, the Snake River at Lower Granite Dam, the Columbia River at The Dalles, and the Willamette River at Salem, Oregon. The Columbia River at The Dalles is a key gaging station for the basin, because its runoff is the sum of the runoff at Grand Coulee, Lower Granite, and the lower

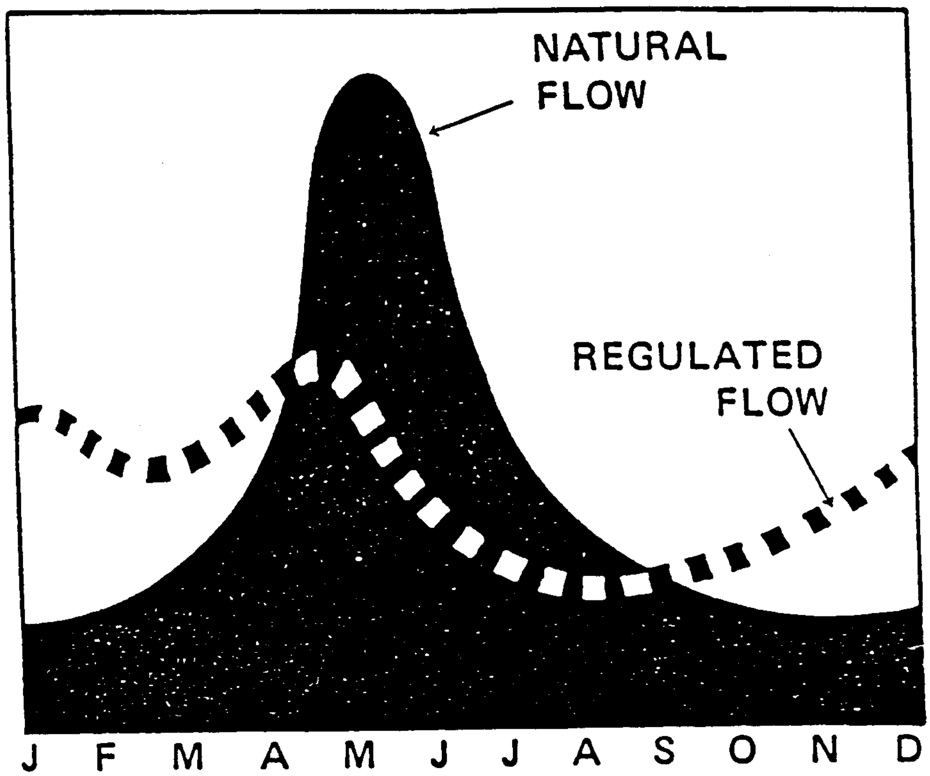

Figure 2. Effect of Regulation on Natural Streamflow Pattern of the Columbia River at The Dalles

Source: Lawrence et al., 1983.

tributaries. Table 1 shows average monthly modified streamflows at The Dalles.

The Columbia River System Dams

The Columbia River System has been developed extensively by federal agencies and non-federal utilities. There are presently 31 federal dams in the system and numerous dams owned and operated by public and private utilities. The Federal Columbia River Power System includes projects on the Columbia, Snake, Willamette, Yakima, Pend Oreille, Boise, Santiam, Payette, McKenzie, Clearwater, Rogue, Flathead, and Kootenai Rivers. The non-federal dams are operated by 20 consumer-owned and 8 investor-owned utilities. Table 2 gives data of interest for major dams and reservoirs on the Columbia and Snake Rivers.

Canadian Dams in the Columbia River Basin

The Columbia River Treaty, ratified by the United States and Canada in 1964, allowed the construction of several dams: Mica (with 12 MAF storage), Hugh Keenleyside (7.1 MAF), Duncan (1.4 MAF) and Libby (4.98 MAF). Regulation of Libby Dam was provided for in the treaty because its reservoir extends into Canada. Under the provisions of the treaty, 15.5 MAF of storage capacity in Canada is jointly managed by the two countries; 5 MAF of the 12 MAF storage in Mica reservoir is regulated independently of the terms of the treaty. Of the 15.5 MAF of treaty storage, 8.45 MAF is regulated for flood control (1.27 MAF at Duncan, 7.1 at Arrow Lakes behind Keenleyside Dam, and 0.08 at Mica), and the remainder is used for power storage. Each country has designated an Operating Entity to be responsible for management of the storage; the Canadian Entity is British Columbia Hydro and Power Authority (B.C. Hydro); the United States Entity includes the Bonneville Power Administration and the North Pacific Division, U.S. Army Corps of Engineers (Power Planning Committee, 1983).

Table 1. Mean Monthly Modified Streamflows* at the Dalles

Month	1926 - 1981 Average (cfs)
October	88,120
November	90,860
December	95,460
January	91,790
February	104,400
March	118,400
April	217,200
May	417,000
June	466,200
July	252,900
August	134,000
September	91,800

* modified streamflows adjusted for irrigation depletion to 1970 level of development

Source: adapted from Columbia River Water Management Group, 1982.

Table 2. Data for Selected Dams and Reservoirs in the Columbia River System

Project	Year Completed	Owner or Operator	Function	Existing Capacity (MW)	Active Storage (1000 AF)
Bonneville	1937	CE	PNR	1,137	138.0
The Dalles	1957	CE	PNR	2,076	53.0
John Day	1968	CE	FPNRI	2,484	535.0
McNary	1953	CE	PNRI	1,127	185.0
Priest Rapids	1961	GCPUD	FPR	820	44.0
Wanapum	1964	GCPUD	FPR	890	161.0
Rock Island	1933	CCPUD	P	544	9.5
Rocky Reach	1962	CCPUD	FPR	1,267	36.0
Wells	1967	DCPUD	FPR	770	74.0
Chief Joseph	1958	CE	P	2,482	116.0
Grand Coulee	1942	BR	FIPR	6,684	5,228.0
Keenleyside	1968	BCH	FRPN	0	7,257.0
Mica	1973	BCH	FP	1,740	12,046.0
Duncan	1973	BCH	F	0	1,400.0
Libby	1973	CE	FP	483	4,980.0
Ice Harbor	1961	CE	PNR	693	25.0
Lower Monumental	1969	CE	PNR	930	20.0
Little Goose	1970	CE	PNR	930	49.6
Lower Granite	1975	CE	PNR	930	53.0
Hells Canyon	1968	IPCO	P	450	11.7
Oxbow	1961	IPCO	P	220	5.0
Brownlee	1959	IPCO	FPR	675	980.0

Owners and Operators:

CE — U.S. Army Corps of Engineers
BR — U.S. Bureau of Reclamation
GCPUD — Grant County PUD
CCPUD — Chelan County PUD
DCPUD — Douglas County PUD
IPCO — Idaho Power Company
BCH — British Columbia Hydro and Power Authority

Functions:

P — hydropower generation or storage
I -- irrigation
F -- flood control
N -- navigation
R -- recreation

Source: adapted from Columbia River Water Management Group, 1982.

Types of Reservoir Projects

Many reservoirs on the Columbia River are pondage or run-of-river projects which have little or no storage capacity compared to the magnitude of the flow passing through them. Examples of run-of-river projects are Bonneville, The Dalles, McNary, and all projects on the mid-Columbia (Priest Rapids to Chief Joseph) and the lower Snake River (Ice Harbor to Lower Granite Dam). Reservoir elevations and discharges at such projects fluctuate on a daily basis.

A storage reservoir is one that generally fills and empties only once a year. An annual storage reservoir will refill each year even if it is drafted to its minimum conservation pool. A cyclic storage reservoir may not refill each year if all its active storage is withdrawn. The annual draft of such a reservoir is determined using forecasts of inflow volume in a manner described in the next chapter. Dworshak, Libby, Mica, Arrow Lakes, and Duncan are examples of cyclic reservoirs.

Uses of Reservoir Projects

Most of the dams in the Columbia River system have been built to perform a variety of functions. Traditional functions include hydroelectric power production, irrigation, flood control, and recreation. System reservoirs have been regulated to provide optimal operations for these uses. Recently, the needs of the Columbia River anadromous fishery have been recognized, and specific operating allowances for downstream fish passage have been mandated by the Northwest Power Planning Council (NPPC, 1982). The following sections examine the major uses of the river system and the benefits derived from each use.

Hydroelectric Generation

Approximately 80 percent of the electricity available in the Northwest is generated by hydroelectric facilities (Public Power Council, 1981). The installed capacity of the existing hydroelectric plants in the Columbia River System as of December 31, 1981, was 29,620 MW (Power Planning Committee, 1983). Hydroelectric projects presently under construction will add approximately 840 MW to the system. If authorized additions of federal projects were constructed, they would add 2,430 MW. If authorized additions of non-federal projects were constructed, 2,050 MW would be added to the system. Therefore, the total existing and potential generating capacity of the system is 34,940 MW.

The Bonneville Power Administration was created in 1938 to be the marketing agency for electric power generated at Bonneville Dam, the first federal dam on the Columbia River. As of September 30, 1979, BPA was marketing the electricity of 30 Federal Columbia River Power System projects, total electricity marketed was 1,248 billion kwh, and total BPA revenues were roughly $3.6 billion (Columbia River Water Management Group, 1980). Table 3 shows BPA sales since its inception.

Seasonal Regulation for Hydropower Production. The Columbia River System has been characterized as a highly storage-dependent system, due to the "great seasonal mismatch" between the pattern of streamflows and energy demand (Schultz, 1979). Energy demands peak in the coldest winter months and reach a minimum in summer months, while streamflows peak in late spring and summer and fall to a minimum in winter. The power system therefore must depend upon regulation of reservoirs to shape the resource to fit the energy requirements of the region. During the coldest months, more than one-half of the flow at The Dalles comes from upstream storage releases (Public Power Council, 1981). Because of the growing economic value of hydroelectric energy in the Pacific Northwest, optimal or near optimal management of storage is a problem of increasing interest. A detailed discussion of the regulation of the Columbia River System for power production is given in Chapter 4.

Table 3. Federal Columbia River Power System Sales

Fiscal years	Revenues ($ x 10^6)	Energy Sales* (kwh x 10^9)
1939-1945	64	25.9
1946-1949	95	36.4
1950-1954	191	80.3
1955-1959	314	133.1
1960-1964	378	150.3
1965-1969	561	215.1
1970-1974	842	305.0
1975-1978	1,168	302.0
1979	297	
1980	512	
1981	705	

* sales inside and outside the region

Source: adapted from Columbia River Water Management Group, 1980 and 1982.

Irrigation

Over 8 million acres of farmland in the Columbia River Basin are irrigated with water from the Columbia River system, enabling semi-arid land in the basin to grow products such as grains, potatoes, fruits, vegetables, and forage crops in large quantities. During Water Year 1981 (October, 1980 to September, 1981), water supplied by the Bureau of Reclamation projects was used to irrigate 2.8 million acres (Columbia River Water Management Group, 1982). Crop production estimates from that irrigation indicate a gross value of about $1.45 billion. In Water Year 1978, 3.1 MAF of stored water were diverted for irrigation. Deliveries of water from storage for water years 1979, 1980, and 1981 were 4.7, 6.2, and 6.3 MAF, respectively (Columbia River Water Management Group, 1980 and 1982). Expanded irrigation development projected for the region will increase the demand for water from storage (State of Washington Department of Ecology, 1980).

Depending on the mix of crops grown in a particular area, the monthly irrigation demands will vary. Water provided for irrigation from each storage project is used to grow a different combination of crops, and therefore, each project will display a unique seasonal irrigation demand pattern (Power Planning Committee, 1975).

The effect of current irrigation development on unregulated flows at The Dalles is shown in Table 4. Irrigation withdrawals are greatest in the months June through September, causing an average reduction in flow over those four months of approximately 65,000 cubic feet per second (cfs). During the remainder of the year irrigation withdrawals are small, and in some months there are net return flows to the river. The annual irrigation withdrawal basinwide is approximately 14.3 MAF.

Flood Control

A devastating flood in 1948 brought the need for flood control in the Columbia River Basin to the attention of the government, and reservoirs such as Franklin D. Roosevelt Lake (behind Grand Coulee

Table 4. Effect of Current Irrigation Development on Unregulated Flows at the Dalles

Month	Depletion or Return Flow* (MAF)	40-Year Average Unregulated Flow (MAF)
October	0.07	5.44
November	-0.51	5.26
December	-0.07	5.66
January	-0.07	5.22
February	-0.61	5.47
March	0.69	7.18
April	-0.64	13.29
May	-1.15	25.82
June	3.19	29.15
July	6.32	16.10
August	3.88	8.60
September	2.40	5.76

* 1984 level of irrigation development

Source: adapted from Dean and Polos, 1983.

Dam) were first regulated for flood control in 1949. Today a significant portion of the active storage of the system is available for flood control on a forecast basis. The U.S. Corps of Engineers is responsible for flood control operations within the basin. In 1974, one of the largest streamflow years since 1894, 36 MAF of storage in McNaughton Lake (behind Mica Dam), Arrow Lakes, Lake Koocanusa (behind Libby Dam), Duncan Lake, Hungry Horse Reservoir, Flathead Lake, and FDR Lake were used to prevent catastrophic flooding in the basin. It is estimated that over $300 million of damages were prevented in the basin in that year alone.

The Pacific Northwest region has two flood seasons annually. Floods from October through March are largely rain produced and generally limited to the area west of the Cascade Mountains; May to July is the period of snowmelt-generated floods, with floods generally limited to the area east of the Cascades. Therefore, regulation patterns of the reservoirs differ markedly in the two areas. West of the Cascades, reservoir storage space is reserved for flood control from October through February. Beginning in February, the amount of space reserved in the reservoirs is gradually decreased as flood potential decreases, until the reservoirs fill, which normally occurs during May. East of the mountains, measurements of snowpack are made monthly beginning in January. These measurements are used to forecast the total seasonal runoff. Storage reservation requirements are based on these forecasts, and the storage reservoirs are drafted by April 1 to a level low enough to control the forecasted volume. Snowmelt reaches a peak in June, and a portion of the high streamflows are stored to reduce flood stages (in high runoff years) or refill the reservoirs (in low runoff years).

Recreation

The Columbia River is used extensively for recreation; almost 750 river miles provide more than 200 water-related recreation sites in Washington state alone (State of Washington Department of Ecology, 1980). Recreational activities include camping, picnicking, boating, swimming, fishing, hunting, and sightseeing. Studies of total recreational visits/month indicate that recreational visits at most of the projects along the river reach a peak in July to August (Power Planning Committee, 1975). Consequently, reservoir operators prefer to have reservoirs as full as possible during the mid-summer, when drafted reservoirs would discourage recreational activities during the peak season.

Columbia River Anadromous Fishery

Before its development for other purposes, the Columbia River yielded between 30 and 40 million pounds of commercial salmon and steelhead annually. Over the last 30 years the fishery has been failing dramatically; annual commercial catch is now approximately 20 million pounds, with an annual economic value of $130 million (State of Washington Department of Ecology, 1980). Table 5 shows the decline of the salmon and steelhead runs since 1938, the year after Bonneville Dam was completed.

The transformation of the Columbia River from a free-flowing river to a series of dams and reservoirs creates several problems for anadromous fish attempting to migrate downstream as well as upstream. Juvenile anadromous fish migrate downstream from the headwaters of the river during the spring freshet, which usually occurs between mid-April and mid-June. Their physiology requires that they complete their journey relatively quickly. Once smoltification (the process which enables juveniles to adjust from fresh water to salt water) has begun, the fish have roughly 30 days to reach the ocean, or serious mortality will occur. Storage of spring runoff in the reservoirs has reduced flow volumes and velocities so that smolt travel time through the reservoirs may be significantly longer than this, even in moderate flow years.

Summary

The development of dams on the Columbia River has brought many benefits to the people of the Pacific Northwest. The Columbia River

Table 5. Salmon and Steelhead Entering the Columbia River*

Year	Spring Chinook	Summer Chinook	Fall Chinook	Sockeye	Summer Steelhead	Coho
1938	--	123	516	168	250	15
1939	152	192	480	125	232	14
1940	90	113	558	196	423	12
1941	108	106	678	174	337	18
1942	77	95	627	94	297	12
1943	131	57	447	73	216	6
1944	56	67	596	25	232	4
1945	83	53	566	11	268	1
1946	124	72	670	101	268	4
1947	186	86	761	335	262	11
1948	126	87	682	143	240	4
1949	138	58	446	53	162	1
1950	120	69	469	113	179	10
1951	206	116	333	204	244	5
1952	246	114	242	319	383	8
1953	229	95	213	260	361	13
1954	189	115	192	180	290	4
1955	281	148	232	245	299	4
1956	217	195	298	202	201	6
1957	253	207	252	147	230	5
1958	198	187	328	313	211	4
1959	138	170	274	271	232	3
1960	134	143	230	179	200	3
1961	162	129	206	58	228	4
1962	200	108	245	39	252	15
1963	147	100	207	65	229	13
1964	169	97	280	105	179	54
1965	176	82	304	55	227	76
1966	175	75	268	169	209	72
1967	151	101	308	165	167	96
1968	134	89	210	135	162	63
1969	216	106	341	76	172	49
1970	171	73	359	85	138	80
1971	168	90	296	150	225	76
1972	281	77	235	123	226	66
1973	233	49	318	61	188	55
1974	108	34	238	44	145	61
1975	104	44	374	58	84	58
1976	78	42	359	44	122	53
1977	144	41	275	100	196	19
1978	129	43	240	18	105	53
1979	51	34	220	53	114	45

*Estimated numbers (in thousands) of upriver salmon and steelhead entering the Columbia River. (Note: upriver is defined as destined above Bonneville Dam; coho count is at Bonneville Dam.)

Source: Lawrence et al., 1983.

system provides about 80 percent of the electric power of the region, allows for over 8 million acres of productive farmland through irrigation and prevents millions of dollars of flood damages each year. Specific requirements for regulation of the reservoirs differ for the competing interests of hydropower, irrigation, flood control, and fish production. Historically, the needs of the fishery have not been considered in the development of reservoir operating policies, and the fish are suffering high mortality rates as a result. The next chapter provides the necessary background to understand the assumptions made in the models used to investigate this conflict and the degree to which these assumptions represent a simplification of the actual system.

CHAPTER 4

The Conflict Between Fish and Hydropower Production in the Columbia River Basin

The conflict between fish and hydropower production in the Columbia River Basin presents a difficult problem for water managers. The regulation of the Columbia River for hydropower production must be accomplished within the constraints imposed by competing uses of the river, such as flood control, irrigation, and most recently, fish production. In addition to outside constraints, the regulation must satisfy provisions of formal operating agreements between several independent hydropower production systems. The resulting regulation, both seasonal and short-term, has been identified as a major factor in the decline of the salmon population of the basin. However, the problem faced by the fish is poorly understood, and researchers cannot accurately predict the results of alternative flow scenarios on salmon survival. Agencies responsible for developing flow recommendations for the benefit of the fish also must consider the impact they will have on the generating capabilities of the power system.

This chapter provides the reader with the background necessary for understanding assumptions behind the computer models used to investigate the conflict between fish and hydropower production. The chapter begins by summarizing the process of developing seasonal operating plans and short-term operation schedules for power production, focusing on the institutional framework within which these schedules are conducted. Then a description of the problems experienced by the fish as a result of the dams and reservoirs is presented, with a history of flow recommendations proposed to alleviate the problems. Finally, a description is given of the Water Budget program of the Northwest Power Planning Council, adopted in 1982 and implemented in the spring of 1984.

Operating Agreements Governing the System

The Columbia River system crosses state and national boundaries and includes projects owned and operated by a multitude of utilities and agencies. As such, a number of institutional agreements are necessary in the development of operating guidelines. The Columbia River Treaty, the Pacific Northwest Coordination Agreement, and the Mid-Columbia Hourly Coordination Agreement are the most significant of these and are discussed in turn. The first two agreements govern the seasonal operation of the system, while the third governs hourly operation of the seven reservoirs on the mainstem of the mid-Columbia.

The Columbia River Treaty. The Columbia River Treaty, ratified by the United States and Canada on September 6, 1964, after twenty years of negotiation, provided for international cooperation in the operation and development of the river. The major provisions of the Treaty require that 8.45 MAF of the 15.5 MAF Canadian treaty storage be operated for flood control purposes. In addition, the U.S. and Canada share equally the additional power generated in the U.S. as a result of river regulation by upstream storage in Canada. The U.S. must also maintain and operate the projects on the mainstem of the river in such a way as to make the most effective use of the improvement in instream flow resulting from Canadian storage releases.

The Treaty had several important results. Because Canada could not, at that time, consume its portion of the new power, its entitlement was sold to the United States for $253.9 million (Columbia River Treaty Permanent Engineering Board, 1977). To finance the sale, the U.S. was forced to develop a market for the surplus power. At this time, Congress authorized construction of the Pacific Northwest-Pacific Southwest Intertie and BPA developed a market for the power in California. A second result of the Treaty is that the increase in storage capacity led the U.S. to add more generating capacity to already existing dams on the mainstem of the Columbia, including projects such as Bonneville Dam and Grand Coulee

Dam. Perhaps the most important result of the Treaty pertaining to system regulation is the evolution of a long-term coordination agreement between the generating utilities which would ensure the U.S. that the benefits of the Canadian storage would be realized.

The Pacific Northwest Coordination Agreement. The Pacific Northwest Coordination Agreement (PNCA), which became effective on January 4, 1965, is a formal contract among BPA, the Corps of Engineers, and 14 public and private utilities, requiring the members to coordinate the seasonal operation of their generating resources for the "best" utilization of their collective reservoir storage, ensuring the usability of the Columbia River Treaty storage at downstream generating plants. The PNCA governs the operations of the individual member systems; the combined system is known as the Coordinated System. An important concept upon which the PNCA is based is that energy and peak capability studies are conducted on the Coordinated System as if it were owned by a single utility. Although this is not a true representation of ownership, the PNCA has provisions for the delivery and return of energy among the member systems and an elaborate accounting system to keep track of transfers of energy between member systems. These provisions validate the single-ownership approach.

Seasonal Regulation

The operations planning required by the PNCA is delegated to the Northwest Power Pool Coordinating Group. The Northwest Power Pool is a group of 19 utilities and agencies which voluntarily coordinate their power systems. Each year, the Coordinating Group develops an operating plan for the July-to-June operating year, pooling the energy loads and resources of the member utilities. Before describing the process of developing an annual operating plan, certain terms used in power planning need definition. The critical period for the Columbia River power system is defined as the period within the 40-year historical streamflow record that produces the least amount of firm energy shaped to the seasonal load pattern when inflows are combined with all available reservoir storage. The critical period lengthens as storage capacity of the system grows; the period now used for planning is the 42-month period from September, 1928 to February, 1932. During the critical period, reservoirs are drafted from full to empty and produce only the Firm Energy Load Carrying Capability (FELCC) of the system (currently the FELCC is approximately 12,000 MW). The FELCC is used as a measure of hydro resource adequacy within the Pacific Northwest; by comparing forecasted energy demands to the FELCC of the Coordinated System, the amount and timing of additional generation needs are determined. Figure 3 shows the forecasts of loads and resources for the Coordinated System for 1980-1981.

Seasonal operation of the system is guided by a set of rule curves developed using the PNCA seasonal hydroelectric simulation model, according to the provisions of the PNCA. The rule curves are operating guidelines which serve a variety of functions: to assure adequate water to meet firm power demands by utilizing storage and streamflows efficiently, to assure adequate storage capacity for flood control, and to assure refill, protecting the ability of the system to meet firm power loads the following year. Three curves of significance are the 1) critical rule curve (CRC), 2) energy content curve (ECC), and 3) variable energy content curve (VECC).

The critical rule curves give end-of-month elevations for each reservoir necessary to produce the FELCC of the system if the critical period streamflows recurred. Operation of the reservoirs below their critical curve levels jeopardizes the ability of the system to meet FELCC in adverse water years. In multiple-year critical periods there is a CRC for each year of the critical period.

The energy content curve is the primary guide for determining how much, if any, non-firm energy will be available for sale from the system. The energy content curve for each reservoir is the higher of its critical rule curve and its assured refill curve (a curve developed by starting the reservoirs full on July 31 and working backward in time to levels resulting in a 95 percent confidence of 98

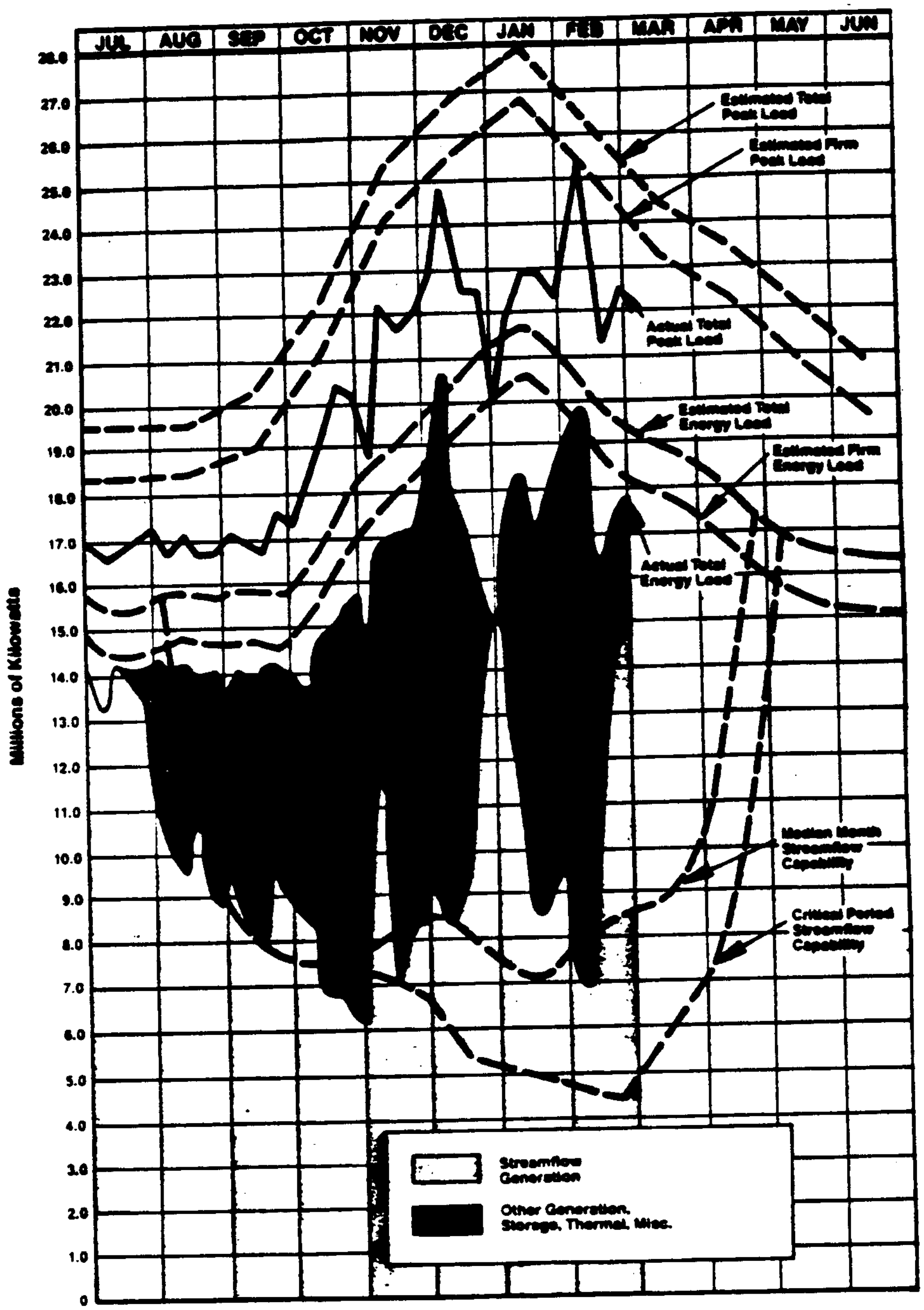

Figure 3. Pacific Northwest Coordinated System Loads and Resources, 1980-81

Source: Bonneville Power Administration.

percent refill). In general, the assured refill curve for a reservoir will only be binding during the refill season (the latter portion of the operating year). To protect the capability of the system to meet FELCC in the next operating year, the PNCA does not allow reservoirs to be drafted below their energy content curves to generate non-firm (secondary) energy. In this way, system refill is given priority over the use of streamflows to generate secondary energy.

The PNCA contains provisions for lowering the ECC's during years in which water conditions are not critical. Starting on January 1 each year, forecasts of January-to-July runoff based on the latest snowpack and precipitation measurements become available to reservoir operators. Updated forecasts are used each month to recompute ECC's for the remaining months of the operating year. If the forecasts predict system refill with high confidence, energy content curves are lowered; such recomputed levels define variable energy content curves. The VECC's allow utilities to use water, beginning in January, which may not arrive until June. Before provisions for lowering the ECC's existed, the system commonly experienced a conservative operating policy in the fall and early winter, followed by a spring and summer with large amounts of surplus energy. The VECC's allow for a less conservative seasonal operating plan by providing greater flexibility in operations.

Weekly Operating Plans

Efforts to regulate the flows on the Columbia River are not limited to seasonal regulation. Each week of the year a detailed operating plan for the next 31 days is prepared, based on forecasts of loads and streamflows likely to occur. The energy content curves or the variable energy content curves are used as guides to the weekly operation of the major storage reservoirs. The weekly plan permits BPA to anticipate energy shortages and to determine the availability of non-firm energy or surplus energy.

Daily Operations and the Mid-Columbia Hourly Coordination Agreement

Short-term operations planning is necessary to accomodate unexpected situations which cannot be incorporated into the weekly operating plan and to maximize the efficiency of the reservoir system. Daily operation plans are developed under the provisions of both the PNCA and the Mid-Columbia Hourly Coordination Agreement.

The seven-plant system on the mid-Columbia, including projects from Grand Coulee to Priest Rapids, is the only power system in the region to operate under an hourly coordination agreement. The agreement became necessary because the hydraulic capacity of each project differs and because the energy requirements of purchasers of mid-Columbia energy differ in quantity and time. Prior to the agreement, water from Grand Coulee Dam was released primarily to meet the needs of BPA's customers. This created a pattern of energy at downstream (run-of-river) dams which did not necessarily meet the requirements of other purchasers. In addition, frequent large fluctuations in reservoir levels and flows created problems for recreators, irrigators, and fish dependent on more stable conditions.

The Mid-Columbia Hourly Coordination Agreement was first implemented in 1974. The basis of the agreement is a single-project, single-owner approach to system operation. The implementation of this approach was aided by the location of the seven dams such that the reservoir behind each dam becomes the tailwater of the next upstream project. This creates a slack water system in which there are no delays in water delivery or power generation. By keeping all reservoirs in the system as full as possible at all times (within certain operating constraints), the efficiency of the seven-plant system is maximized. The general procedure followed is to release water from Grand Coulee to fill the downstream reservoirs after they have been drafted for peaking.

The daily demand for power in the Pacific Northwest follows the pattern shown in Figure 4. Although the power generation of the system must follow this pattern, the pattern of generation from each individual plant need not be similar to this pattern. Some projects

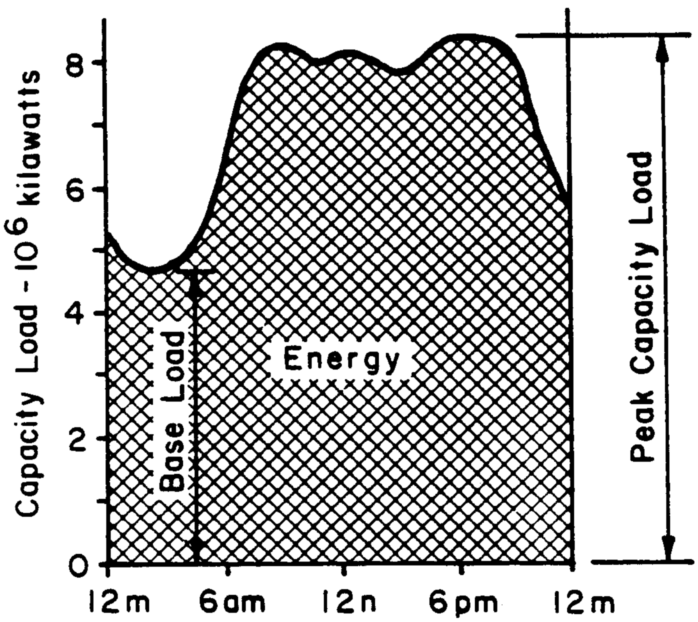

Figure 4. Daily Load Shape for the Pacific Northwest

Source: Power Planning Committee, 1975.

produce a fairly constant power output over the course of the day; others vary their output considerably. Figure 5 shows how the federal hydroelectric plants in the region operate together to satisfy the federal system load on a typical day.

The degree of fluctuation in power production and the degree of fluctuation of discharge for a given project on a given day is a function of many variables. The most important are size and shape of the daily power demand, amount of water in the river, the number of generators operating that day, and streamflow regulations required for non-power river uses. Other factors such as plant size, reservoir storage capacity, and the characteristics of plants directly upstream and downstream of the project determine the extent to which the plant can vary its power production.

Developing operating policies for the Columbia River power system is a complex task due to the size of the system, the different operating agreements under which the system must function, and constraints imposed on the system operation by non-power interests. The agencies responsible for resolving the conflict between fish and hydropower production in the basin face at least as difficult a task, complicated by the fact that the problem faced by the anadromous salmonids is not as well-defined. It is believed that the critical factors in the decline of the fishery have been identified, but the relationship between these factors is uncertain at best. The remainder of this chapter discusses each of these factors and the proposed solutions to the problem.

Blockage of Spawning Grounds

Construction of Grand Coulee Dam in 1942 blocked a large portion of the spawning areas of the basin for salmon and steelhead, because the dam lacked fish passage facilities. With the construction of Chief Joseph Dam on the Columbia just below Grand Coulee Dam, and Hells Canyon Dam on the Snake River, essentially two-thirds of the Columbia River Basin was rendered inaccessible to fish migration, because fishways were neglected at these dams also. The nine

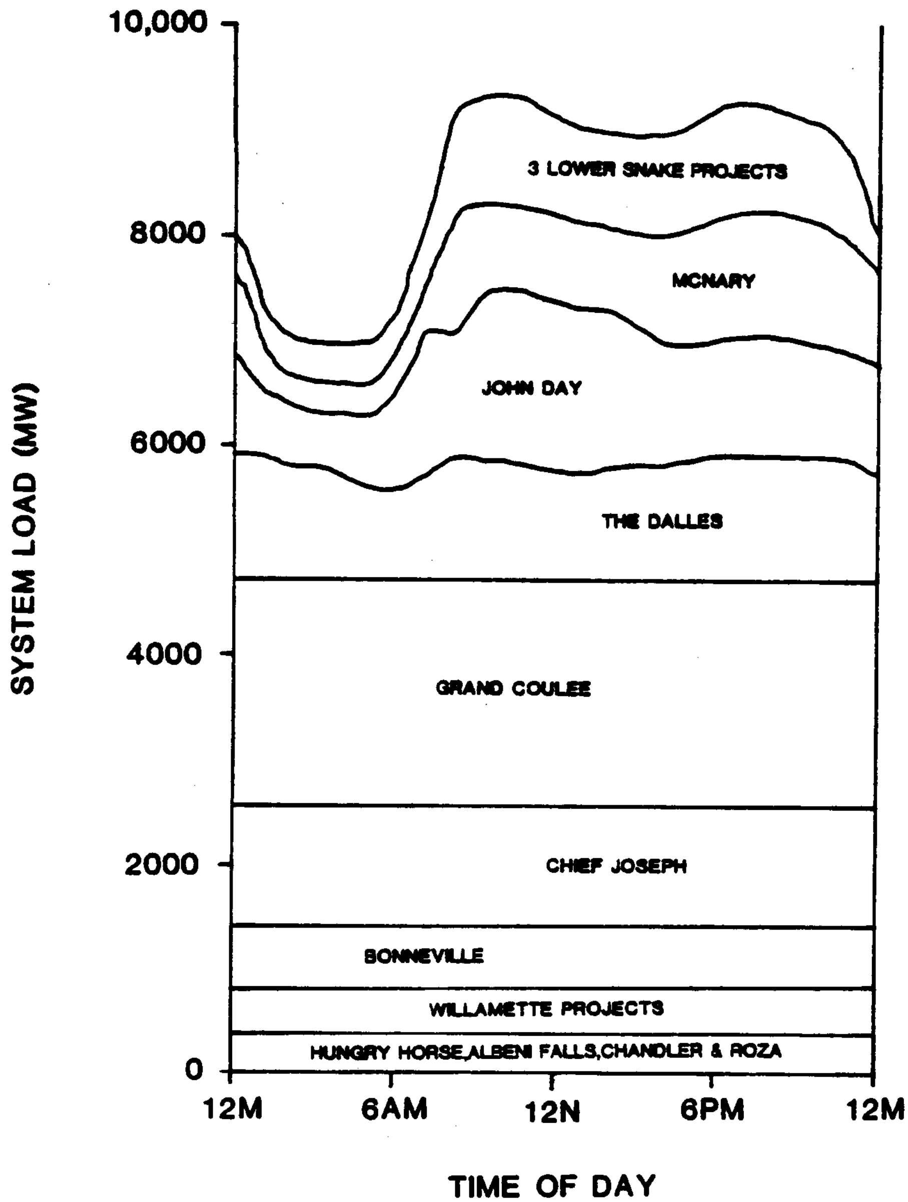

Figure 5. Allocation of Load Among Hydro Projects of the Federal Columbia River Power System

Source: Power Planning Committee, 1975.

remaining dams on the Columbia below Chief Joseph Dam included fishways, as did the four dams on the lower Snake River below Hells Canyon Dam.

Adult Dam Passage

Adult migrants attempting to pass these dams are delayed even in high-flow years. This delay results in increased exposure to predation and high nitrogen supersaturation from the water at the base of the dam. Such supersaturation causes the mortality of substantial numbers of adult fish (Beiningen and Ebel, 1970). In addition, fish which do pass the dam are subject to fallback, passing back downstream over the spillway or through the turbines. Fallback at Bonneville Dam has been shown to be a significant problem when heavy spill occurs (Gibson et al., 1979).

Juvenile Mortality

The Columbia River Fisheries Council (CRFC) believes that although adult mortality from dam passage may be quite serious at some dams, mortality of juvenile salmon and steelhead due to river regulation represents the most serious problem (CRFC, 1978). They have identified three major problems for downstream migrating juveniles resulting from the series of dams and reservoirs: 1) the velocity of water traveling through reservoirs is much lower than velocity of an equal flow traveling through a free-flowing stream because of the greatly increased cross-sectional area; 2) storage of water during the spring-summer period for later release for power production decreases river flow and water velocity when they are most needed by downstream migrating juvenile salmon and steelhead trout; and 3) a majority of the water released is passed through turbines at dams, except in high flow years.

A History of Flow Recommendations

The first set of flow recommendations for the Columbia was published in 1972 for the National Marine Fisheries Service (NMFS)

(Wagner, 1972). In a report based on historical river conditions, fish count records, and results of fish research programs, Wagner made recommendations concerning minimum and maximum flows, daily and hourly rates of change in flow, and tailwater and forebay levels required to operate fish passage facilities. Anticipating a need for a more refined set of recommendations, the fisheries agencies appointed a Subcommittee on River Flows through the Columbia Basin Fishery Technical Committee to develop flow recommendations for the mid and lower Columbia and lower Snake rivers. In these recommendations, published in 1978, three aspects of flows were considered: minimum daily average flow, minimum instantaneous flow, and requirements for spill and turbine operation. Recommendations were made for each month of the year at 11 dam sites on the river.

The Subcommittee considered the impact of these three factors on flow-related losses and turbine-related mortalities. It was argued that minimum daily average flow was the major variable determining flow-related losses. The claim that minimum daily average flow is related to the delay of juveniles migrating downstream is well-supported (Raymond, 1968; Collins et al., 1975). It has also been shown that the effect of delay on the smoltification process results in high mortality rates for juvenile fish attempting to migrate to saltwater environments (Adams et al., 1975). To establish the recommendations of minimum daily average flows, turbine-related losses (direct turbine mortalities, spillway mortalities, and predation on stunned fish) and overall survival of juveniles migrating past eight dams were observed for a variety of flows. For each flow level, flow-related survival was calculated by dividing overall survival by turbine-related survival.

The resulting curves are shown in Figure 6. They indicate that for very low flows, juvenile survival past the eight dams is drastically reduced due to the effect of delay on the smoltification process. Less drastic reductions in survival for very high flows are the result of nitrogen supersaturation. The minimum daily average

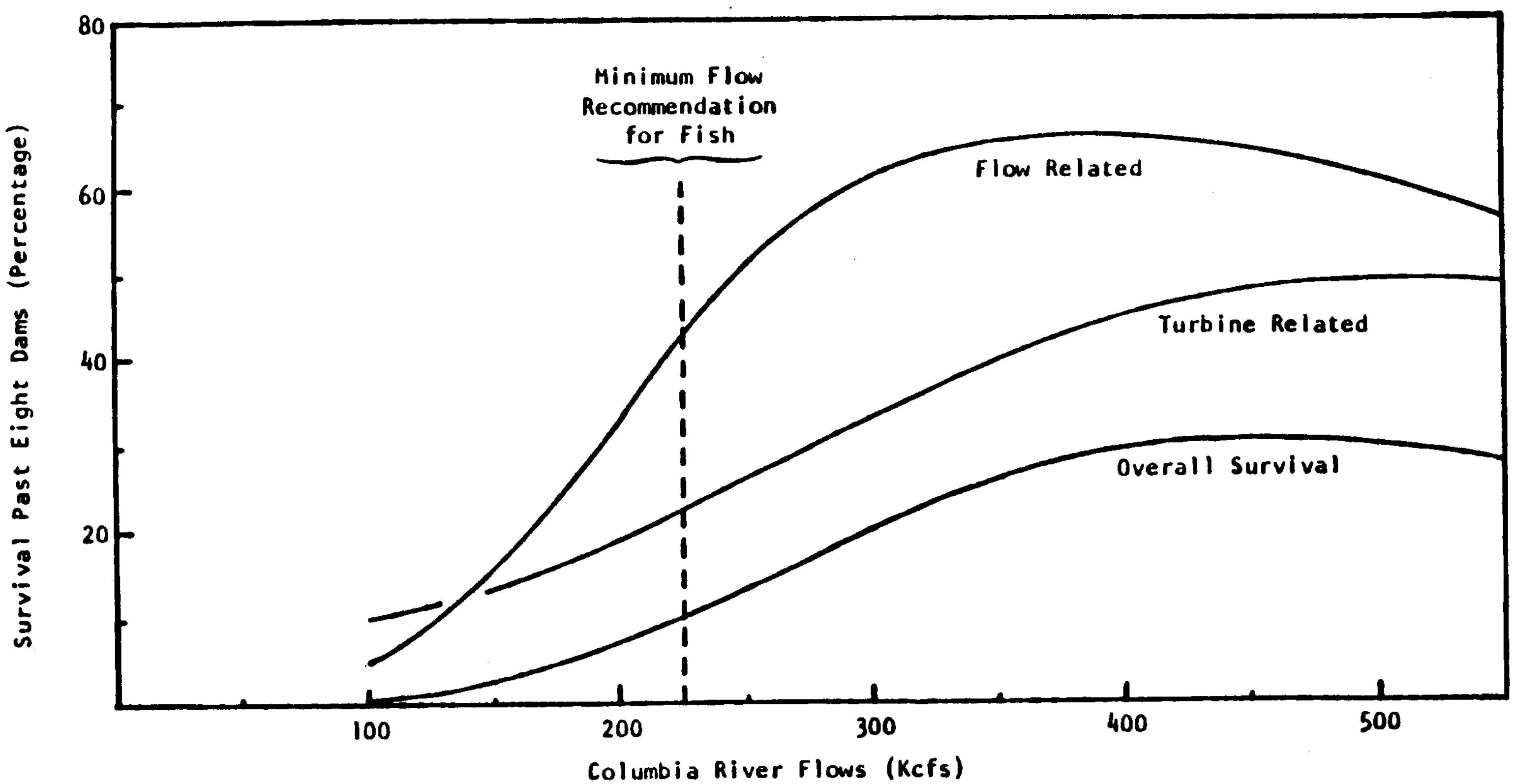

Figure 6. Survival Curves for Juvenile Migrants Past Eight Dams

Source: Columbia River Fisheries Council, 1978.

flows recommended on the basis of these curves are at the low end of the range of "moderate flows", as defined by NMFS.

The need for minimum instantaneous flows arises from the possibility that minimum daily average flows may be satisfied by balancing a period of extremely low flow with a period of high flow. Undesirable impacts of low-water levels of short duration include 1) reduction of effective spawning area, 2) dewatering and destruction of eggs in gravel, 3) trapping of fry in gravel just before emergence and death of fry by exposure, and 4) stranding fry in pools where they die from lack of oxygen or bird predation. The Subcommittee made recommendations for minimum instantaneous flows which they believed would restrict the degree of hourly "peaking" fluctuations, and thereby limit the magnitude of these effects. A key concern for setting the level of minimum instantaneous flows was the productivity of the Columbia River below Priest Rapids Dam, which is the last remaining natural spawning area for fall chinook. Studies by the Washington Department of Fisheries (Bauersfeld, 1978) showed severe fishery losses at the permitted 36,000 cfs flow level and provided evidence supporting a minimum instantaneous flow of 70,000 cfs at Priest Rapids.

Spill and turbine manipulation recommendations were based on concerns over turbine-related mortalities, which can be as great as 30 percent at some Columbia River dams. Because spillway mortality for mainstem Columbia River dams is relatively minor, the Subcommittee recommended that 20 percent of the discharge be passed over the spillways rather than through the turbines from April 15 to June 15, the period corresponding to peak juvenile migration. The CRFC claims "even in moderate flow years, modest harvestable runs have only been produced from juvenile migrations associated with spills averaging better than 20 percent of the total discharge" (CRFC, 1978). Spill recommendations are considered essential by the CRFC until other techniques to bypass juveniles from the turbines are perfected.

In 1979, the CRFC published a revised set of recommendations based on minimum and optimum flows. Optimum flows were recommended for the peak smolt migration period and were identified through consideration of curves such as those shown in Figure 6; maximum survival corresponding to optimal flow level. However, the Instream Flow Work Group, an interagency committee established by federal resource and water management agencies, estimated that providing optimum flows in May would result in a 6,300 MW decrease in FELCC (U.S. Army Corps of Engineers, 1982). Consequently, when the next set of flow recommendations were made for the Northwest Power Planning Council (NPPC) in 1981, optimum flows were set aside in favor of minimum flows due to the severe impact on FELCC.

Because minimum flow requirements would still result in a 90 percent mortality rate during low water years, the Columbia River Inter-Tribal Fish Commission was dissatisfied with the recommendations of the Committee and conducted a study to determine the capability of the system to provide minimum and optimum flows for fish during low flow years (Karr, 1982). Earlier work had shown that there would be relatively few problems providing minimum flows during average or high runoff years. Karr examined historical streamflow data to determine surpluses and deficits in monthly runoff volumes required to produce needed flows for fish. The Dalles, Priest Rapids, and Lower Granite dams served as control points where low runoff periods were examined. Karr found that minimum flow requirements could be met during low flow years with storage regulation for firm hydropower production on the Columbia River control points (The Dalles and Priest Rapids Dam), but not on the Snake River control point (Lower Granite Dam). Optimum flow requirements could not be met in general during both winter and spring. A significant finding of the study was that the capability of meeting optimum as well as minimum flows could be increased by timing the releases to coincide with daily or other short-term fish movements, rather than working with monthly streamflow averages.

This practice could reduce the volume of storage releases necessary to meet recommended fish flows.

The Water Budget

The concept of shaping the flows as suggested by Karr led to the Water Budget, part of the Fish and Wildlife Program adopted by the Northwest Power Planning Council in November, 1982 (NPPC, 1982). The program was initially implemented on the Columbia River in the spring of 1984. The Water Budget is a volume of water specified by the NPPC to be used for shaping flows from April 15 to June 15, the period of juvenile migration. The actual shaping of the flows is accomplished by two Water Budget managers appointed by the fish and wildlife agencies and the tribes. Separate Water Budgets are established for Priest Rapids and Lower Granite dams, which determine the flows at The Dalles.

The volume of the Water Budget was derived from the flow recommendations of the fish and wildlife agencies and the tribes. The NPPC added positive differences between the average monthly flows achieved under fish and wildlife agency recommendations and average monthly flows achieved during the critical period for firm power requirements. The calculated sum of differences is 4.03 MAF, of which 2.39 MAF is released at Priest Rapids Dam, and 1.64 MAF at Lower Granite Dam. The flows required for firm power production are 76 kcfs at Priest Rapids from April 15 to June 15 and 50, 65, and 60 kcfs at Lower Granite for April 15-30, May, and June 1-15, respectively. The Water Budget is not used to achieve flows greater than optimum flows recommended by the tribes (140 kcfs for both Priest Rapids and Lower Granite dams).

A further constraint on the implementation of the Water Budget is that it must not interfere with the regulation needs of non-power interests such as irrigation and flood control. BPA has developed Water Budget implementation scenarios for low, average, and high flow years which attempt to relieve potential conflicts between competing interests (Figure 7).

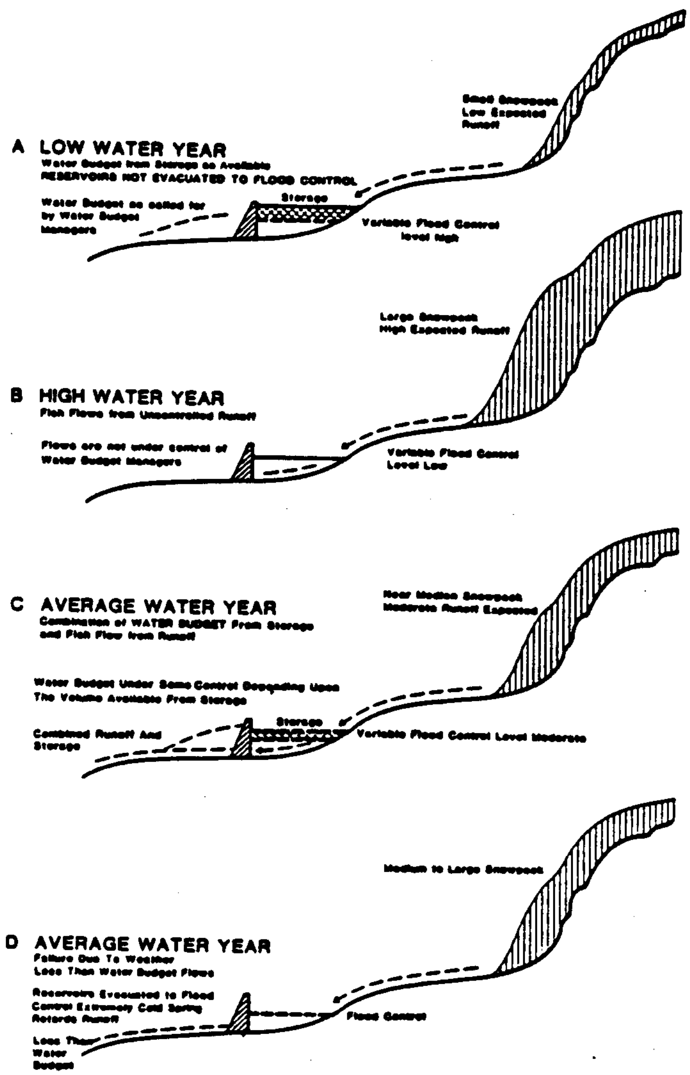

Figure 7. Water Budget Implementation Scenarios

Source: Lawrence et al., 1983.

In an attempt to quantify the impact of the Water Budget on the power generating capability of the system, the Instream Flow Work Group used the Corps of Engineers' seasonal hydro regulator model to produce an estimate of reduction in FELCC resulting from the Water Budget. The next chapter reviews the various hydro regulator models currently being used by water management agencies for such studies, as well as other models capable of assessing impacts to hydropower peaking capability and system reliability from various flow regimes and power load scenarios. It then describes several models dealing with fish production on the Columbia and characterizes levels of complexity for the two classes of models.

CHAPTER 5

A Review of Columbia River Fish and Hydropower Production Models

This chapter reviews simulation models currently being applied towards management of the hydropower and fish resources of the Columbia River Basin. Hydropower models summarized are categorized as seasonal hydro simulation, hourly hydro simulation, and system reliability models. Models are identified which can analyze impacts of alternative fisheries enhancement efforts. This chapter includes a description of each model, its use, and a characterization of its level of complexity as determined by indicators of structural and processing complexity.

Seasonal Hydro Simulation Models

The seasonal hydro simulation models reviewed in this study are similar in purpose and design. The models estimate the power generating capability of the Pacific Northwest hydro system under varying conditions of loads and streamflows. Regulation of the river for hydropower production subject to non-power uses and project operating constraints is simulated. The provisions of both the PNCA and Columbia River Treaty are embedded in the logic of each model. The models are deterministic, chronological simulations employing monthly time steps for a desired period of analysis, usually several years.

The PNCA Seasonal Regulation Program (HYDREG), maintained by the Northwest Power Pool Coordinating Group, is used as an aid in the establishment of seasonal guidelines for coordinated operation of the reservoirs of PNCA parties. Specific users include the NWPP Coordinating Group, which uses the model to determine FELCC and to develop rule curves, the Intercompany Pool, Pacific Gas and Electric Company, and Puget Power. The model is used for short-term operations studies, determination of regional shortage and actual system refill. HYDREG models the hydro resources of the Columbia River (including Canadian treaty storage), the Willamette River, and the lower and upper Snake River. The model may be run in any one of nine modes including priming, proportional drafting, and run-to-rule curves. In the priming mode, the user specifies a priming chain, (a list of reservoirs available for draft or fill and their priority of use) and the program varies the drafts or fills to produce a prespecified system generation. This mode is used primarily for critical period studies. Proportional draft mode is generally used to perform the 40-year study, an analysis of resources and loads from a particular contract year applied to each of 40 years of historic streamflow. In this mode, the operation of the system is simulated according to critical period rule curves, with reservoirs proportionately drafted to meet a specified load. The run to rule curve mode requires that end-of-period storage levels equal those prescribed by various rule curves. The program may be used to maximize energy generation for the system while satisfying constraints on flood control, minimum instream flows, flow reductions for fish spill and bypass flows, maximum turbine capacity, channel discharge, and maximum rates of change. For each reservoir, the program calculates energy generation and peak project capability.

The model is maintained on an IBM 3033 OS/VS system, and execution requires 256K decimal bytes of working storage. The program has four major subroutines, contains approximately 2000 lines of executable FORTRAN IV code and is run in batch mode. Although execution of the program is a once through process, it may require multiple runs to achieve a balanced run (system load is met and no constraints are violated), depending on the mode of operation.

BPA's Hydroelectric Power Planning Program (HYDRO) simulates the power generating capabilities of the existing Pacific Northwest hydro system under various loads and flows over a multiple year time horizon. The model is currently used by the BPA branches of Power Capabilities and Power Supply for rate and marketing studies and studies forming the basis of the West Group Forecast, an 11-year forecast of loads and resources for the following areas: Washington State, Idaho panhandle, portions of Oregon, northern California, Montana, and southern Idaho. Hydro resources of the Columbia River (including Canadian treaty storage), Willamette River, and lower Snake River are included in the analysis. The upper Snake River hydro resources are not modeled. However, the existing generating capacity of these projects is a small fraction of the total Columbia River system capacity (on the order of 0.4 percent of the total capacity). HYDRO simulates the operation of as many as 50 storage reservoirs. The program may be run in any of three modes: priming, proportional draft, or fixed mode. In fixed mode, the user specifies storage at each reservoir for each period, and the program determines power generation and maintains constraints. The model assumes perfect coordination of system reservoirs.

Embedded in the model is the Critical Period Optimizer Program (CPOPT), a routine to determine end-of-period storage levels which optimize power generation during the critical period. CPOPT was developed by BPA and Boeing Computer Services in 1973 and was, at that time, one of the largest nonlinear programming problems of its kind to be solved. The problem involves about 6000 variables, 4000 linear equations, 11,000 inequality constraints, and a nonlinear objective function (Hicks et al., 1974). The objective of the routine is to minimize the sum of weighted penalties for power deficits, non-uniformity, and project constraint violations. The program starts with a user-supplied approximation to the solution and iterates to find the optimal solution. The output of CPOPT then becomes input into HYDRO.

HYDRO and CPOPT are currently maintained on BPA's CDC 6500 NOS/BE system. Both are modular FORTRAN IV programs; HYDRO is composed of approximately 30 subroutines and CPOPT of 15 subroutines. HYDRO contains approximately 3000 lines of executable code; CPOPT contains about 2000. The programs require 100K words of central memory and 70K words of extended core storage for execution.

Another important seasonal hydro simulation model is Hydro System Seasonal Regulation Program (HYSSR), developed by the North Pacific Division of the Corps of Engineers. Its purpose is similar to those of the preceding two models in that it simulates the power generating capabilities of the Pacific Northwest hydro system under varying loads and flows. The Corps uses the model primarily for refill studies. Other uses include flood control analyses, irrigation depletion and fish flow studies, and U.S./Canadian treaty studies. The upper Snake River hydro resources are not modeled.

HYSSR may be run in any of four modes or a combination of these modes. In delta storage mode, the user specifies the change in storage for each reservoir for each period. In the fixed rule curve level mode, the user specifies the rule curve level to which each reservoir is operated for each period. In meet system loads mode, the user specifies the load to be met, and the program determines the change in storage required for each reservoir in order to satisfy the power requirement. The last mode available operates reservoirs to meet specified target streamflows at various control points in the system. The program works from upstream to downstream control points, calculating power generation and checking constraints at each project. The model is run in batch mode on the Corp's Amdahl V-7B, requiring 276K decimal bytes working storage. The program is written in FORTRAN IV with a modular structure of approximately 30 subroutines and 5000 lines of executable computer code.

A fourth seasonal hydro simulation model was developed at Washington State University (Hanson and Millham, 1981) and has been used by the Washington State Department of Ecology to determine loss of firm power capability resulting from a variety of storage management policies. The model was patterned after HYDRO and HYSSR; monthly time periods are used in determination of the firm power capability of the system. The base regulation, arrived at after several runs of the model, gives end-of-period storage levels for 18 storage projects which appear to maximize total energy output over a fixed critical period (the model uses the 44 1/2 month period from

July 1, 1928 to June 30, 1932). Unlike HYDRO and HYSSR, the model only simulates regulation in the critical period. Another important difference between this model and the others is that this model conducts economic analysis, associating losses in firm power capability with a replacement cost. Each alternative storage regulation, other than the base regulation, results in a loss of firm power, which might be baseload or peaking power. Lost baseload is replaced by nuclear or coal-fired thermal power, at a cost of 35 mills per kwh. Peaking replacement cost is taken as 82 mills per kwh, assuming replacement with a simple gas turbine.

A heuristic, forward-looking model called PASO (Peaking Alternatives System Operation), patterned after BPA's CPOPT, was developed by Hanson and Millham in parallel with the WSU Snake-Columbia Basin Simulation Model just described. PASO was designed to conduct automatic regulation, developing an optimal set of end-of-period storage levels. Both models have been validated over a wide range of base power flows by comparison with the results of HYDRO and HYSSR. The models were developed for use on the IBM 360/65 and are run interactively. Execution requires 94K decimal bytes storage.

A composite one-reservoir model of the Coordinated System was developed by BPA and Stanford University in the early 1960's. The model was used to demonstrate the benefits derived from optimal operation of the system rather than rule curve operation (Rosing and Garza, 1967). The optimal operating policies were identified using stochastic dynamic programming. To keep the number of state variables small, a single reservoir storing potential energy was used. Tranformation to potential energy was necessary to account for the fact that water has a different potential for generating energy at different plants in the system. A composite generation function giving total system generation for each month as a function of outflow and storage at the beginning of the month was determined using the results of a 30-year regulation of BPA's HYDRO model. Optimal operating policy minimized the expected sum of costs associated with lost revenue, operating steam plants, importing energy and curtailing firm load. The model determined the optimal value of system generation each period, not the allocation of this generation among the various plants. This optimal policy was then compared with generation resulting from rule curve operation. Composite critical rule curves and energy content curves were calculated for the system by adding potential storage associated with the curves at each reservoir. After the comparisons between operating policies were made on the historical 30-year flow record, the model was run with 500 years of synthetic potential energy inflows, for which inflows at The Dalles were used, and optimal operating policies were determined for this sequence. Flood control constraints were not incorporated into the model. Simulating 30 years of rule curve operation took about 1 1/2 minutes on the IBM 7040. Computer time for obtaining the optimal operating policy for one month was approximately 4 minutes.

Hourly Hydro Simulation

The next class of models used for management of Pacific Northwest hydropower resources are the hourly simulation models, originally developed by the North Pacific Division of the Corps and currently maintained by the Corps and BPA. The two agencies' versions of the model are so similar that they are reviewed as one model. The purpose of the model is to demonstrate the performance of added hydropower generating capacity at existing and proposed plants of the West Group of the Northwest Power Pool. Hydraulic aspects of hourly hydro operation are modeled, including adequacy of pondage, impacts of tailwater and forebay fluctuations, and impacts of minimum flows on generating capacity. The model was designed primarily for use in sizing individual hydropower plants and testing operating constraints. Hourly operation of each project in the system is simulated for a period of one week. The system includes hydro resources of the Columbia River and the lower Snake River. BPA's version of the model also includes hydro resources of the Willamette

River. The Corps uses the model to determine plant sizing, turbine selection, usability of pumped-storage, and for calculating average forebay and tailwater elevations for input into their seasonal hydro simulation program, HYSSR. BPA uses the model to study sustained peaking, load management, and load allocation scenarios.

The model employs a relatively simple simulation process. Hourly system loads, modeled as constants in the Corps' version and as random variables in BPA's, are distributed to three sources: thermal, hydro, and pumped-storage. In BPA's version of the model, pumped-storage and thermal resources are aggregated as miscellaneous resources. Available thermal resources are fully utilized and residual loads are met by hydro resources. For each project, the programs calculate hourly values for required release, power generated, and forebay and tailwater elevations. System constraints include the amount of pondage used and limits on the rates of change of forebay and tailwater fluctuations, to limit the impacts of peaking operations.

The programs are executed in batch mode on the Corps' Amdahl V-7B OS/VS2 system and BPA's CDC NOS/BE system, requiring 194K decimal bytes working storage. The program structure is singular with 10 functional subroutines. The Corps' version has approximately 2300 lines of executable FORTRAN IV code, while BPA's contains about 3000. Multiple runs are frequently required to obtain a balanced run.

System Reliability Models

The pondage programs just described are not suitable for determination of system reliability, because of the large number of runs required to develop data adequately describing the normal range of river and power system conditions and the simplifications in the thermal generation modeling. The seasonal hydro simulation models are also not suitable for assessing system reliability; a major simplifying assumption of these models is that hydro unit maintenance does not affect project energy output. A class of models designed specifically for the purpose of addressing the question of system reliability has been developed, utilizing analytical or Monte Carlo simulation to determine various indices of reliability. These models consider both thermal and hydro resource outage possibilities.

One such model is Loss of Load Probability Analysis (LOLP), originally developed as an aid in implementing the Pacific Northwest Coordination Agreement. The specific purpose of the model is to determine the probability that a forecasted peak load will not be met by forecasted resources. The model is used by BPA for resource planning and by the NWPP for determination of firm peak load carrying capability, critical peaking period, and reserve requirements for the PNCA.

The model is based on the assumption that monthly peak load forecasts are normally distributed. From this distribution, a distribution of daily forecast peak is derived. A capacity outage table, giving the probabilities that various amounts of capacity are forced out, is defined for each plant, based on unit outage and common outage data input by the user. Given the peak load distribution and the capacity outage table, the program calculates the probability of failure to meet the load L, for 100 distinct load levels. This is the probability that the load equals L, multiplied by the probability that there will be greater than C-L megawatts of forced outage (where C equals system capacity). The program determines the amount of load that produces a particular loss of load probability (LOLP) and the amount of peak which must be added to, or subtracted from, forecast load to produce the target LOLP. This amount is used to determine the reserve capacity required by the PNCA. A major limitation of the model is that it does not consider the duration of unit outages.

The LOLP program is run on BPA's CDC NOS/BE system and on NWPP's IBM 3033 OS/VS system in batch mode. Execution requires 100K decimal bytes storage and is a once through process for each year of simulation. The program is singular in structure, with one subroutine for updating capacity outage tables, and contains 270 lines of executable FORTRAN IV code.

Another system reliability model employing probabilistic-analytical simulation is the Pacific Power and Light (PP&L) Reliability Model. The model determines the ability of specified resources to satisfy a specified level of reliability and is based on assumptions similar to those of the LOLP model. The PP&L model is an extension of BPA's model. It models multiple outage states on both hydro and thermal units, calculates several additional reliability indices and contains a version of the LOLP program within its computer code. Indices calculated include LOLP, the Loss of Load Expectancy (LOLE), Energy Loss, Expected Load Curtailment, and the Firm Peak Load Carrying Capability for each month of simulation. PP&L uses the program for generation expansion studies and in conjunction with their Production Cost Model to determine operating costs of various levels of system reliability. The method used to calculate the indices is independent of the area and the number of units in a study; this makes the model extremely flexible. The program is maintained on PP&L's IBM 3033 OS/VS system and utilizes dynamic storage. The structure is modular, with a main program and 15 subroutines. The program contains approximately 900 lines of executable code.

The Energy Reserve Planning Model (ERPM), developed by the Coordinating Group of the Northwest Power Pool, employs a larger degree of aggregation and a less realistic treatment of load forecast uncertainty than the two reliability models just described. System operation is modeled with 3 four-month periods per year, for up to 25 years. The system is modeled as one composite reservoir. Total hydro energy capability, natural streamflow, reservoir status and reservoir constraints are represented as single values; only historic flows at The Dalles are required to represent system hydro resources. Forecast load is modeled as a constant. The model uses Monte Carlo simulation to determine thermal unit in-service dates, thermal unit availability, and area streamflow. The program may be run in any of nine modes which correspond to modes of operation of the hydro system. Results include levels and probabilities for system parameters such as surplus for markets, load served, and secondary load served. The NWPP and BPA's Branch of Power Investigations use the model annually to determine probabilities of resource insufficiency for the West Group Forecast. Additional uses of the model include assessing the impacts of construction delays on new thermal generating units and planning generation additions based on energy surplus/deficiency targets.

ERPM is run in batch mode on NWPP's IBM 3033 OS/VS system and BPA's CDC 6500 NOS/BE system, and requires 250K decimal bytes working storage. The program is modular, with 4 subroutines and approximately 650 lines of executable FORTRAN IV code. Ancillary programs for preprocessing of data contain an additional 500 lines of code.

Another one-reservoir model assessing system reliability was developed at BPA's Division of Power Supply (Dean and Polos, 1983). The model provides statistics on the frequency and magnitude of failures of the system to meet firm loads by performing a large number of regulations using synthetic flows. Inflows are 1000 sets of 100-year sequences of monthly unregulated flows at The Dalles.

The model begins by modifying the inflows for the effects of irrigation development and subtracting average monthly irrigation depletions from the inflows. Monthly power demands are satisfied by releasing a constant volume of water every year (the model assumes a constant head for each month over all years). A single reservoir having the amount of active storage capacity in the Coordinated System upstream of The Dalles is used to regulate the modified streamflows. The reservoir is drafted to meet the required flows for firm power generation and is filled when streamflows are greater than flows required for firm power generation. The model contains no power generation function and does not consider flood control constraints on storage. The model has been used by BPA to generate statistics on failures resulting from various levels of firm power demands and storage capacities. The program is run in batch mode on BPA's CDC 6500 NOS/BE system. It is singular in structure and has approximately 230 lines of executable FORTRAN code.

Summary of Hydropower Management Models

Simulation models used for management of the Pacific Northwest hydro resources may be classified as seasonal and hourly hydro simulation and system reliability models. The seasonal models are used by various agencies to establish seasonal guidelines for operation of the system reservoirs. Hourly hydro models provide information on the detailed hydraulic aspects of system operation and are useful in plant sizing, turbine selection, and determination of adequacy of pondage. Both of these classes of models assume that hydro unit maintenance does not affect project energy output, and therefore they do not fully address the question of system reliability. A class of models has been developed to assess system reliability under conditions of resource outage. These models employ a greater degree of temporal aggregation than the hourly hydro models and a higher degree of uncertainty than both the seasonal and hourly simulation models. Table 6 is a listing of the models just described and a summary of their uses.

Models Used to Investigate the Conflict

Several models have been used to quantify trade-offs between the competing interests of fish and hydropower production. The remainder of this chapter is a discussion of how the models already reviewed have been used for this purpose and a review of models capable of quantifying the impact of alternative solutions on the river's fish population.

The Columbia River Anadromous Fish Management Model (CRFISH) was developed for the Pacific Northwest Regional Commission to evaluate the biological and economic effects of proposed dam improvement or hatchery projects (Johnson, 1981). The model determines the effects of upgrading existing hatcheries or changing the stocks of fish,

Table 6. Selected Power Production Models Developed for the Columbia River System

Model	Purpose	Developer/User	Use
* PNCA Seasonal Regulation Program (HYDREC)	Monthly Regional Hydro Simulation	M.S. Schultz/NWPP	Coordination Agreement Studies
* Hydroelectric Power Planning Program (HYDRO)	Monthly Regional Hydro Simulation	H. Kasai/BPA	West Group Forecast Regulations, Rate Studies, Marketing Studies
* Hydro System Seasonal Regulation Program (HYSSR)	Monthly Regional Hydro Simulation	COE/COE	Multi-Purpose Water Use Studies
WSU Snake-Columbia Basin Simulation Model	Monthly Regional Hydro Simulation	Hanson, Millham/WSU	Multi-Purpose Water Use Studies
Stanford Composite Potential Energy Model	Monthly Regional Hydro Simulation	Rosing, Garza/BPA	Optimization of Operating Policy
* COE Pondage Program	Hourly Regional Hydro Simulation	R. Shepard/COE	Generation Expansion Studies
* BPA Pondage Program	Hourly Regional Hydro Simulation	COE-BPA/BPA	Operations, Marketing
* Loss of Load Probability Analysis (LOLP)	Loss of Load Analysis	M.S. Schultz/ NWPP, BPA	PNCA Reserve Requirements
* PP&L Reliability Model	Multi-Index Analysis	Boeing Computer Services/PP&L	Reliability of PP&L System
* Energy Reserve Planning Model (ERPM)	Energy Resource Insufficency Analysis	Schultz, Duncan, Lewis/NWPP, BPA	West Group Forecast
BPA's One Reservoir Model	System Reliability	Dean, Polos/BPA	System Reliability Studies

* adapted from: (PNUCC, 1981)

Source: Pacific Northwest Utilities Conference Committee, 1981.

building new hatcheries, dam modification (which influences only dam passage mortalities, not flow related mortalities), and changes in fishing regulations and patterns. Information on life cycles of anadromous fish species are incorporated into the model, with emphasis on juvenile and adult migration stages. The model identifies the most economically beneficial combination of enhancement and dam modification projects by maximizing either undiscounted benefit/cost ratio or benefits, subject to user discretion.

The Columbia River dam system is not internal to the model. The user must define the system by specifying the number of dams and their location on the river. This allows for considerable flexibility as to the complexity of the system being modeled. The model can handle up to 19 dams and 5 rivers. The user determines the effects of dam improvements on the population by specifying juvenile and adult dam passage mortality rates at each dam. Similarly, the user enters the value of a scaling factor which increases or decreases the efficiency of a fishery; changes in regulatory policies are not explicit input to the model. The program is maintained on the University of Washington's CDC computer system. The FORTRAN code listing is approximately 7000 lines and contains 58 subroutines, requiring 32K words of memory. A FORTRAN precompiler called TFOR must be used prior to executing the program.

BPA's hydroregulator (HYDRO) has been used to identify conflicts between hydropower and fish production on the Columbia River. In June, 1979, the Pacific Northwest River Basins Commission initiated a program to analyze the economic and environmental trade-offs associated with alternative levels of Columbia River system water use. Using HYDRO, monthly streamflows for several alternative storage regulation schemes during the 40-year planning period of 1928-1968 were evaluated to determine the capability of the system to meet minimum streamflow requirements for fish. Three control points were used: McNary Dam on the mid-Columbia, Priest Rapids on the Upper Columbia, and Ice Harbor on the Snake River. Flows were depleted by the 1980 level of irrigation development. The analysis concluded that minimum fish requirements could be satisfied at the two Columbia River control points with regulation of system storage, but could not be satisfied at the Snake River control point during low runoff years (Karr, 1982).

The Washington State Department of Ecology (WDOE) has developed a model to evaluate the economic impacts of alternative instream flow regimes proposed for the Columbia River (WDOE, 1981). A simple analytical model determines effects on the salmon fishery, while output from BPA's HYDRO and PONDAGE programs is used to assess effects on the power generating capability of the system. Fish production effects are analyzed for commercial and sport fisheries in river and ocean zones. The fish production model presumes benefits to survival of anadromous juvenile migrants at different flow rates; flow-related smolt survival rates are interpolated from the survival curves provided by the Columbia River Fisheries Council for each of several flow options. Survival rates are applied to hatchery and wild salmon smolt production to estimate impacts to the number of migrant smolts reaching the ocean. Next, data relating smolt production to returning adult runs and relating runs to commercial and sport catches are used to calculate flow-related increases in these variables for a particular flow regime. An empirical equation giving equilibrium market price per pound of salmon caught as a function of per capita consumption (a function of commercial landings of salmon) allows estimation of the economic impacts of a flow option on the commercial fishery. Economic impacts on the sport fishery are estimated using an empirical equation giving value per fishing day as a function of catch per fishing day. The total fishery enhancement is the sum of the commercial and sport fishery enhancements.

Economic impacts to hydropower production result from minimum average daily flows and minimum instantaneous flows. Different losses are incurred with each flow regime. In this simple model, minimum average daily flows are assumed to cause overgeneration only during low runoff periods. A further assumption is that this extra energy would be stored in a system external to the region and returned at some later time. Such a practice would result in transmission losses, acceptability losses (incurred when the system storing the energy returns it at a time when it cannot be fully utilized by the Pacific Northwest), and storage charges. Minimum instantaneous flows result in a loss of daily or weekly peaking capacity. Estimates of overgeneration or loss of peaking capacity resulting from a particular flow regime are developed by BPA using their simulation models. Economic impacts from overgeneration are determined by summing the transmission and acceptability losses, which are valued by the cost of replacement with thermal generation, and storage charges. Loss of peaking capacity is valued in terms of investment costs for gas turbines, considered the next best available peaking resource.

The model was used by the Washington State Department of Ecology in 1981 for the impact statement required for their Columbia River Instream Resources Protection Program (CRIRPP). They estimated the effects of four instream flow regimes on the anadromous fishery and the system hydropower production. The regimes analyzed were:

1. Flows set by the Committee on Fisheries Operations in 1979 (assigned baseline status);
2. Minimum instream flows proposed by CRFC in 1979;
3. Minimum instream flows proposed for the CRIRPP (CRFC flows with provisions for reductions during low runoff periods); and
4. A proposal by the Washington Environmental Council for a minimum instantaneous flow of 70 kcfs at Priest Rapids and a minimum average daily flow of 275 kcfs at Bonneville during the critical juvenile anadromous fish migration period.

The Corps of Engineers' seasonal regulator, HYSSR, has been used in many recent studies to identify conflicts between fish and power production. The model was used by the Instream Flow Work Group in 1979 to examine the physical ability of the system to provide minimum streamflows recommended by the CRFC. The Dalles and Priest Rapids Dams were Columbia River control points, and Lower Granite Dam served as the Snake River control point. Estimated 1995 levels of irrigation depletion were used. An alternative in which storage was regulated to satisfy minimum fish requirements, without constraints imposed by other purposes, indicated that requirements on the Columbia could be met during all months in the 1928-1968 period, but requirements on the Snake could not be met during low runoff years (Karr, 1982). The study also demonstrated that at least 4 MAF of additional storage would be needed on the Snake River to eliminate deficits for minimum flows.

The model was also used by the Instream Flow Work Group to estimate the impact of numerous fish flow alternatives on FELCC and the ability of the reservoirs to refill. Alternatives analyzed included the CRFC minimum and optimum instream flow requirements, a sliding-scale scheme where releases for the fish were based on volume of runoff, and the draft and final proposals of the Water Budget (U.S. Army Corps of Engineers, 1982). These estimates were given consideration by the Power Council in the decision making process which led to the adoption of the Water Budget.

A Characterization of Complexity

In Chapter 2, various indicators of the components of complexity were identified which allow a characterization of model complexity to be made. These indicators included: the length of the computer code, the resources used by a computer in executing the program (time and storage requirements), the number of modes of operation, and the processing complexity of the program, indicated by whether the solution is arrived at iteratively or with one run and the number of ancillary programs required for model implementation. Table 7 is a summary of the indicators of structural and processing complexity for the models reviewed in this chapter. Because comparisons of computer execution times cannot be made without information on the performance of the machines the models are run on, a value of MIPS (millions of

Table 7. Indicators of Complexity for Selected Models

Model	Length of Code	Typical Execution Time/ Max Storage Requirements	Computer Executed On and MIPS[a]	Number of Modes of Operation	Multiple Runs or Once Through	Data Pre-Processing Programs Req'd
* HYDREG	2000	45 CPU seconds for 40 yrs/ 256K decimal bytes	IBM 3033/2-5	9	multiple runs	several
* HYDRO, CPOPT	3000, 2000	3500 decimal seconds, for 40 yrs 2050/100K words central memory, 70K words extended core storage	CDC 6500/3.5-4	3	multiple runs	several
* HYSSR	5000	35 CPU minutes for 40 yrs/ 276K decimal bytes	Amdahl V-7B/6.5	4 or more	multiple runs	several
WSU Snake-Columbia Basin Simulation Model	N.A.	5-6 CPU seconds/94K decimal bytes	IBM 360/65/2-5	N.A.	multiple runs or once through	N.A.
Stanford Composite Potential Energy Model	N.A.	1 1/2 - 4 CPU minutes/ N.A.	IBM 7040/2-5	N.A.	once through	N.A.
* COE Pondage	2300	1-3.5 CPU minutes/194K decimal bytes	Amdahl V-7B/6.5	N.A.	multiple runs	0
* BPA Pondage	3000	1-3.5 CPU minutes/194K decimal bytes	CDC 6500/3.5-4	N.A.	multiple runs	0
* LOLP	270	13 CPU seconds/100K decimal bytes	CDC 6500/3.5-4	N.A.	once through	1
* PP&L Reliability	900	N.A./dynamic storage	IBM 3033/2-5	N.A.	once through	1
* ERPM	650	80 CPU seconds for a 2000-game run/250K decimal bytes	IBM 3033/2-5	N.A.	once through	1
BPA's One-Reservoir Model	230	N.A.	CDC 6500/3.5-4	1	once through	1
CRFISH	7000	N.A./32K words central memory	CDC Cyber 750/9	2	once through	1

N.A. - not available

[a] Millions of Instructions Per Second

Source: Pacific Northwest Utilities Conference Committee, 1981.

instructions per second) is given for each machine. This value is a relative measure of the power of each computer; given in conjunction with the execution time of each program it provides a means by which to compare the complexity of the models.

Consideration of Table 7 leads to the conclusion that the seasonal hydro regulator models maintained by the NWPP, BPA, and the Corps are highly complex. Each program has thousands of lines of executable code, requires significant computer resources, and may be run in several modes. In addition, the programs may require multiple runs in order to arrive at a balanced solution (in which all constraints are met), and several ancillary programs are required for data preparation and management. Simplifications to the system modeled, primarily by including fewer reservoirs, and therefore fewer interactions between variables, cause the WSU Snake-Columbia Basin Simulation Model and the Stanford Composite Potential Energy Model to be less complex than those used by the agencies. Execution times are shorter and there are fewer modes of operation. The hourly simulation models also appear to be less complex than the seasonal hydro regulators. Execution time is significantly lower, the programs may only be run in one mode, and no ancillary programs are necessary. The system reliability models are the least complex of any of the hydropower management models. They have considerably fewer lines of code, execute more quickly, have fewer modes of operation, and are once through processors.

The single computerized model that deals with fish production in the basin may also be characterized as complex. However, this model fails to take into account what fisheries biologists assume is the most important factor in the decline of the salmon: the timing of the flows. Consequently, this model may not be used to estimate the value of various flow scenarios to fish production. Use of the model is further restricted by the fact that the values of many of the input parameters are highly uncertain. For instance, actual juvenile mortality rates at dams may range from 10 to 40 percent and vary with the flow rate at each dam, but the Washington State Department of Fisheries uses a constant 21 percent at each dam (Packard, 1984).

The lack of computer simulation models to address this issue is a result of the nature of the problem. Research to date has not satisfactorily quantified all the critical parameters. There is no more value to using a complex model with uncertain values for the parameters than there is to using a simple model for which all critical input values are known. The next chapter describes the development of a model of the Columbia River system which minimizes data requirements and processing complexity and produces estimates of trade-offs between fish and hydropower production. In this model, the critical parameter, the volume of release for the fish during the peak juvenile migration period, is the sole parameter influencing fish production. Use of survival curves in conjunction with the model allows estimation of benefits to fish production resulting from various fish flow scenarios.

CHAPTER 6

The Columbia River Integrated Systems Program

A computer model was developed for this study to investigate the effects of the Water Budget on various key operating characteristics of the Columbia River power system. The complexity of the model was minimized to allow it to be run inexpensively on a large set of synthetic inflows. However, it was important to incorporate planning criteria and operational constraints in sufficient detail to produce an acceptably realistic representation of the system. The model, noted here as the Columbia River Integrated Systems Program (CRISP), integrated basin-wide irrigation depletions, primary and secondary power generation, mandatory Water Budget releases and minimal flood control capability into annual planning and operations of a composite reservoir representing the combined storage of the Coordinated System upstream of The Dalles. The model is not intended to be used as a guide to operations but to examine and display how various parameters affect long-term system characteristics.

Two versions of CRISP were developed. The first version uses the 40-year record of historical flows chosen as the basis for planning in the Pacific Northwest Coordination Agreement. There were two 40-year regulations run with CRISP: one incorporating the Water Budget into planning and operations and one without the Water Budget. Results of the 40-year regulations were compared with results from the Corps of Engineers' Base 3 and Water Budget 4 studies, which were conducted for the Instream Flow Work Group in 1982 using the hydro regulator, HYSSR. The model was then modified so that it could be used with synthetic flow data. This procedure provides a large number of experiments upon which to base comparisons between various operations/planning scenarios. This chapter describes the assumptions behind the model and results of the 40-year regulations and synthetic flow regulations.

BPA's One-Reservoir Model

CRISP is based on the one-reservoir model of the system developed at BPA (Dean and Polos, 1983) and described briefly in Chapter 5. The model used 1000 sets of 100-year monthly synthetic flow sequences at The Dalles as inflows. The synthetic flows were generated using a log normal ARMA-Markov model (Lettenmaier and Burges, 1980). Average 1984 irrigation depletions for the basin upstream of The Dalles were subtracted from the inflows to arrive at inflows comparable to the modified flows used in the 40-year regulation studies. Irrigation demands greater than half the inflow in any given month were reduced to half the inflow to preserve water for instream uses.

Flow volumes necessary to satisfy firm power demands in each calendar month were calculated using the critical period regulation for the 1983-84 operating year prepared for PNUCC's Northwest Regional Forecast. For each calendar month, the average of the regulated flows at The Dalles which occurred in that month within the critical period was taken as the regulated flow necessary to satisfy firm loads for the entire system. This approach is valid because of the high correlation (R^2=0.96) between regulated flows at The Dalles and system generation (total load). Because total load is equivalent to firm load within the critical period, The Dalles outflows within the critical period represent flows needed to satisfy firm loads.

Using the 1983-84 regulation, Dean and Polos (1983) determined that 36 MAF was released from storage during the critical period. This volume was used as the capacity of the composite reservoir. To verify that this reservoir would draft from full to empty during the critical period, but not at any other time in the 40-year record, they used this volume to regulate the modified flows to satisfy firm loads.

Modifications to BPA's One-Reservoir Model

CRISP uses results from the Corps of Engineers' Base 3 study as a base case scenario against which to compare the 40-year Water

Budget regulation. All depletions and loads were established at 1985 levels. Firm power flows and the storage capacity of the reservoir were calculated as previously described. Modified flows supplied by BPA were used as inflows. A critical period regulation was done to verify that the storage capacity was correct. The reservoir drafted from full to empty at the end of the 42 months.

Several factors are incorporated into CRISP which are absent from BPA's one-reservoir model. The major difference between the two models is secondary power generation; CRISP simulates the production of secondary energy according to the provisions of the PNCA. Critical rule curves, assured refill curves, energy content curves, and variable energy content curves were developed for the composite reservoir using the procedures outlined in Section 7 of the PNCA (1964) for individual reservoirs and serve as guides to the production of secondary energy. Figure 8 is a flow diagram for CRISP.

Development of ECC's. For the first six months of the operating year (July through December), the first year critical rule curve was used as the lower limit to which storage could be drafted to produce secondary energy (energy content curve). The first year rule curve was produced by the critical period regulation previously described. Operations during the next six months of the operating year are more complicated. For these months, assured refill curves and variable refill curves are calculated and used to determine the base energy content curve and variable energy content curves. The assured refill curve gives end-of-month storage values which provide a 95 percent confidence of refill by July 31 of the next operating year, the end of the refill season. To calculate this value for the month of January, for example, the 40 values of February through July runoff minus minimum discharge requirements and deductions for upstream refill are ranked. Firm power flows were used as minimum discharge requirements, except in the Water Budget regulation, in which the May minimum discharge requirement was the sum of the firm power flow and the 4 MAF required release for the Water Budget. The values for

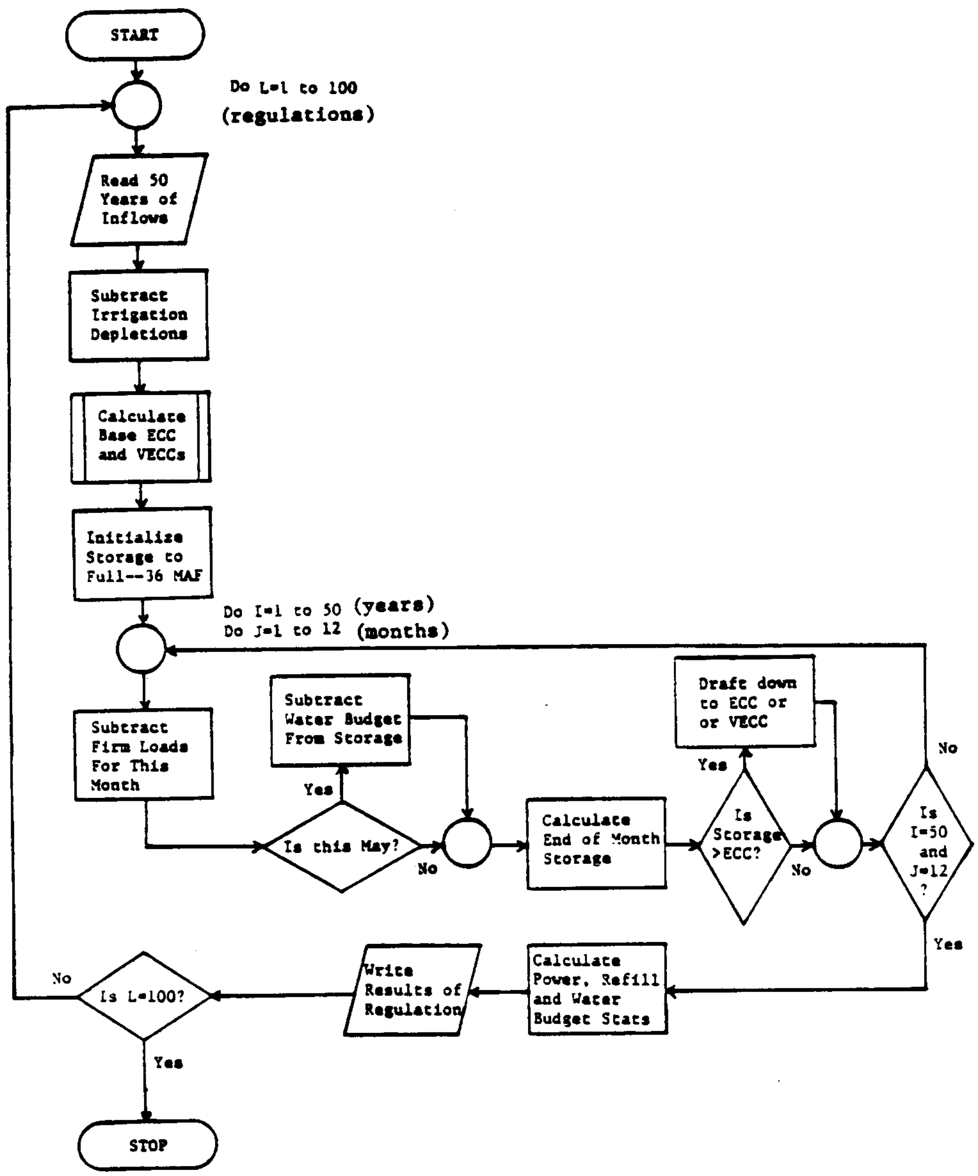

Figure 8. Simplified Flow Diagram for CRISP

upstream refill account for the holding of water in the Canadian non-treaty storage capacity in the basin. As an estimate, it was assumed that this capacity would be refilled at a constant rate between April 1 and July 31. After the 40 values are ranked, the second lowest value is used to estimate the amount of water which will be available for system refill from the end of January through the end of July, 95 percent of the time. This value is subtracted from the storage capacity of the composite reservoir to give the lowest end of January storage which will allow the composite reservoir to refill by the next July 31. After the assured refill curve is calculated, the energy content curve is taken as the higher of this curve and the first year critical rule curve.

Calculation of VECC's. In actual operations, forecasts of volume of runoff become available January 1 and are updated monthly. Consequently, the VECC's are updated monthly. The hydro regulators, however, are based on a known record of flows and use these flows as forecasts. Therefore, VECC's are calculated once each year, and there is no need to update the curves monthly because the forecasts do not change monthly. The variable refill curve is computed similarly to the assured refill curve. Minimum discharge requirements and upstream refill volumes are subtracted from the inflows. However, instead of ranking these volumes and taking the second lowest for each period to determine the quantity available for refill, the 95 percent hedge is subtracted from the forecasted volume inflow. The 95 percent hedge is based on the error in the cumulative forecast volume inflow which is associated with a 5 percent exceedance probability. It represents a safety factor to protect against overestimates of predicted inflows. It is calculated once for each month by taking the 40 values of differences between actual and predicted inflows from the end of the month through July 31. The agencies assume that these errors are normally distributed. The error which will be exceeded 5 percent of the time is determined by multiplying the standard error of these 40 values by 1.645. Once the variable refill curve is obtained by subtracting the volume available for refill from the storage capacity of the reservoir, the VECC is the lower of the ECC and the variable refill curve. The third year critical rule curve serves as a lower bound for the VECCs in all years.

Maximum Turbine Capacity as a Limit to Secondary Generation. CRISP forces secondary generation until storage drafts down to either the ECC (July through December) or the VECC (January through June). The only limit to secondary generation above those curves is the maximum turbine capacity of the system, for which the maximum turbine capacity at The Dalles was used. Since each dam in the system has a different turbine capacity, this will be a source of error in the model. However, the error introduced was small, given that there were only 3 months in the 40-year regulation in which this constraint was binding.

Power Generation. Another difference between the Dean and Polos model and CRISP is that CRISP includes a power generation function. Regressions of 40 values of system generation and The Dalles releases for each calendar month conducted at BPA indicated a linear relationship between these two variables (Dragoon, 1984). Correlation coefficients for every month were between 0.899 (in September) and 0.99 (in July and February). For each calendar month, an equation of the form MW = a(kcfs) + b was used to compute average monthly generation, where a and b are constants which vary monthly. The equation allowed calculation of firm power, secondary power, and firm deficit for all months.

Flood Control. BPA's one-reservoir model and CRISP also differ in the manner in which flood control is handled. Dean and Polos allowed storage capacity of the reservoir to remain constant throughout the year. CRISP incorporates a composite flood control rule curve. In actual operations during the first three months of the operating year, the reservoirs east of the Cascades (upstream of The Dalles) are not operated for flood control. The flood control rule curve in CRISP allows the reservoir to be at full capacity during these months.

During October through December, reservoirs are drafted for flood control to the same level each year. To determine the flood control rule curve for the composite reservoir from October through December, maximum storage volumes of all storage reservoirs in the system were added together for each month. Data were supplied by the Corps of Engineers. By December 31, the day before the first forecast of volume of runoff is available, storage in the composite reservoir must be drafted to 30.95 MAF.

Differences Between CRISP and HYSSR

Modeling Flood Control. Actual flood control operations beginning January 1 require that runoff volume forecasts at each project be used to determine the amount of storage space to be available by April 1, when flooding becomes a hazard. The Corps' HYSSR model uses the forecasts at each project to determine the storage to be reserved for flood control at each reservoir. One procedure to develop a composite flood control rule curve would be to add together the January, February, and March maximum storage volumes at each project for each year and average them over the 40 years for each month. This procedure was discarded because the resulting composite flood control rule curve would not be representative of any actual procedure followed. Therefore, the flood control rule curve for these months allowed storage to remain at full capacity.

The Corps uses the concept of Initial Controlled Flow (ICF) at The Dalles for flood storage reduction during April through June in the key problem areas in the basin: the Columbia River downstream of The Dalles and the vicinity of the treaty projects. They have found that regulating the treaty projects for the ICF at The Dalles (not to exceed 600,000 cfs) protects the area in the vicinity of the treaty projects from floods (Dodge and Fodrea, unpublished). Again, there is a problem developing a composite flood control rule curve to represent this practice. The flood control rule curve in CRISP allows the reservoir to remain at full capacity during this part of the year. To determine the magnitude of error resulting from this simplification, the model keeps track of the number of years in each sequence that regulated flow at The Dalles was greater than 600,000 cfs during the second half of the operating year.

Modeling the Water Budget. The participation of the Idaho Power Company in the Water Budget was not included in CRISP. It was incorporated into the Corps' Water Budget 4 study through a schedule of Brownlee Reservoir elevations to which Idaho Power operates. Although the participation of the company is recommended by the Water Budget Program, Idaho Power has not yet made a firm commitment to participate. A draft implementation plan has been drawn up, in which the volume of Brownlee release is dependent on forecasts of April to July volume runoff as of April 1 at Brownlee (Idaho Power Company, 1984). Releases from Brownlee would only be made in May for the Water Budget and only in years when the April to July volume runoff forecast is less than the median from the 40 years of record (4.27 MAF). As synthetic data are not available for inflows at Brownlee, it was decided not to model Idaho's participation in the Water Budget in CRISP. If synthetic flows at Brownlee were available, this effect could be easily incorporated into the model.

Firm Loads. The constant monthly firm loads used in CRISP are a close approximation of the firm power loads used in HYSSR. The HYSSR model calculates firm hydro system load by taking a constant monthly value every year and subtracting the load met by independent hydro resources and thermal power, which varies year to year. Therefore, the firm load carried by the system in any month varies slightly from year to year.

Power Discharge Requirements. The monthly power discharge requirements (PDR's) in HYSSR vary each year according to the forecasts of inflow. The energy content curves are sensitive to the PDR's, and the Corps and BPA routinely use the PDR's to increase or decrease secondary generation in any month. For the sake of simplicity, the same monthly PDR's are used in CRISP for all years. Table 8 summarizes the major differences between BPA's one-reservoir model, CRISP, and HYSSR.

Table 8. Differences Between BPA's One-Reservoir Model, CRISP, and HYSSR

Feature	BPA's One Reservoir Model	CRISP	HYSSR*
Number of Reservoirs	1 composite	1 composite	maximum of 80
Modes of Operation	1	1 (run to rule curves)	4 or more
Inflows	synthetic (1000 sequences of 100 years)	historical (40 year record) or synthetic (100-1000 sequences of 50 years)	historical (40 year record)
Irrigation Depletions	constant year to year, up to 1/2 inflow	varies with historical record or constant year to year, up to 1/2 inflow	varies with historical record
Flood Control	storage capacity constant all months	fixed rule curve 1st 6 months, full capacity 2nd 6 months	fixed individual rule curves 1st 6 months, variable individual rule curves 2nd 6 months
Firm Power Loads	represented by monthly flow volumes, constant year to year	represented by monthly volumes, constant year to year	firm hydro load varies period to period due to independent hydro resources and thermal power
Secondary Generation	none	draft to composite ECC or VECCs, limited by maximum turbine capacity	individual ECCs, VECCs, limited by secondary market, individual maximum turbine capacities
Calculation of ECC, VECCS	none	fixed monthly PDRs, allowances for Canadian non-treaty storage	variable PDRs based on volume of runoff, allowances for upsteam storage at each project
Power Generation Function	none	MW = aQ + b, a and b vary monthly	MW = (H/K)Q for each plant, H/K = f(head, variable efficiency)
Water Budget	none	May: 4 MAF after firm load at The Dalles, no drafting of Brownlee	May: 3.57 MAF release at Grand Coulee, 0.92 MAF at Dworshak, 0.31 MAF at Brownlee; targets of 130 kcfs and 85 kcfs at Priest Rapids and Lower Granite, respectively
Outputs to Measure Impacts of Water Budget	frequency and magnitude of firm load failures	statistics on average annual generation, average monthly generation, and refill of composite reservoir	FELCC, ave. annual generation individual reservoir refill for 40 year record

Source: Summarized from U.S. Army Corps of Engineers, 1982a, 1982d.

40-Year Regulations

There were two 40-year regulations run using CRISP: one incorporating the Water Budget into planning and operations and one without the Water Budget. To make the regulation comparable to the Corps' Water Budget 4 study, the Water Budget period was modeled as occurring in the month of May, not the actual April 15 to June 15 Water Budget period specified by the Program. The Water Budget regulation required that minor changes be made to the program. First, 4 MAF of water were released in May after firm power flows were released, regardless of whether this forced storage to go below VECC's. To incorporate this release into annual planning, the PDR for the month of May was increased by 4 MAF. Firm power flows were recalculated for the Water Budget run to correspond to regulated outflows at the Dalles given by the Water Budget 4 study.

The critical period regulation used to verify storage capacity for the Water Budget regulation indicated that there would be a deficit in firm power flow of 0.65 MAF in the last month of the critical period, even when firm power flows were shaped to correspond to regulated flows given by the Water Budget 4 study. The drafting of Brownlee Reservoir for the Water Budget, which was incorporated in the HYSSR regulation but not in CRISP, may explain this deficit. Brownlee storage releases would be seen as extra inflows into the composite reservoir, since storage at Brownlee is not included in the Coordinated System. The extra inflows could be used as releases to avoid drafting storage from the composite reservoir.

Results of the base case and Water Budget regulations using CRISP were compared with those obtained by the Corps using HYSSR. A summary of these results is given in Table 9. For each output, the HYSSR value was assumed to be the true value with which to calculate errors in the CRISP output. It can be seen that the one-reservoir model does a very good job of determining average annual power generation, with an error of approximately 1 percent. When individual values of annual generation were compared with HYSSR results, it was found that these errors were small. The maximum

Table 9. Comparison of Results from 40-Year Regulations Using CRISP and HYSSR

Model Output	CRISP	HYSSR	Percent Error[a]
Base Case Regulation:			
Refill Failure Rate, Percent	12.5	-	-
Average Annual Generation, MW	15,495	15,327	1.1
Average July to December Generation, MW	13,919	12,971	7.3
Average January to June Generation, MW	17,097	17,727	-3.6
Water Budget Regulation:			
Refill Failure Rate, Percent	15.0	-	-
Average Annual Generation, MW	15,395	15,281	0.7
Average July to December Generation, MW	13,666	12,663	7.9
Average January to June Generation, MW	17,153	17,943	-4.4
Water Budget Misses	0	8 at Priest Rapids 10 at Lower Granite	-

[a] as measured by (CRISP value - HYSSR value)/HYSSR value

error was 7 percent in one year, with all other errors less than 5 percent. Average July to December and January to June generation errors are somewhat larger but still acceptable (< 8 percent). To determine whether these errors could be explained by the power generation function (based on an imperfect regression fit), errors in regulated outflows were calculated, but these errors were almost as large as errors in power generation. Errors in monthly average power generation were large, because CRISP regulations were run to rule curves, and the HYSSR regulations were run to meet firm load and a specified secondary market (base case study) and to meet target streamflows (Water Budget study). Therefore, it was felt that dividing the year into two distinct periods was the finest temporal disaggregation for which results of the two models could be compared. Because the estimates of the impacts to generation are on the same order of magnitude as the errors, a conclusion as to the impact of the Water Budget on power generation cannot be made on the basis of these two regulations. For this reason, it was felt that results of the synthetic flow regulations, which provided a large data base with which to estimate critical output parameters and the opportunity to analyze trends over a broad range of flows, should be analyzed before a conclusion about the impact of the Water Budget could be drawn. The remainder of this chapter is a description of the synthetic regulations and their results.

Modifications to CRISP for Synthetic Flow Regulations

Minor modifications to the model were necessary before it could be run using the synthetic flows. First, the planning horizon was changed from a 40-year period to a 50-year period, to reflect the fact that the agencies will soon begin using a 50-year record of flows in their studies. The other change dealt with adjustments to inflows for irrigation. The 40-year regulation used unregulated flows modified by the 1985 level of development irrigation depletions as inflows. The synthetic flows are unregulated, but not modified. The effects of irrigation depletions had been removed. Therefore, it was necessary to adjust the synthetic flows by 1985 irrigation depletions, as was done in BPA's one-reservoir model. An average irrigation depletion, or return flow, was calculated for each month using historical records and was subtracted from the synthetic inflow to get the equivalent of a modified flow.

Synthetic Flow Regulations

CRISP was used to investigate the effect of the Water Budget on the power generating capability of the system. As the volume of water released for fish during the period of peak juvenile migration has been identified as the critical factor determining their survival rate, it was felt that varying this parameter and noting the impacts on hydropower generation would be an appropriate method for generating trade-offs between the two uses of water. The parameter was varied by introducing a constant which was multiplied by the current volume of the Water Budget release (4.0 MAF). This multiple was varied from 0.0 to 2.0. In each case, the volume of Water Budget release was incorporated into the May power discharge requirement. The effects of varying two other parameters in the model were also examined. These parameters were: 1) the size assumed for the standard errors of forecasted inflows, and 2) the percent hedge. The size of the standard errors represents historical success at predicting inflows; an improved ability to accurately predict inflows would be associated with a decrease in the size of the standard errors. The effect of varying this parameter on system operating characteristics, such as power generated, was investigated to determine the value of improved forecasting ability in long-term studies. The size of the standard errors was varied by introducing a constant to multiply the errors by. Each time period error was multiplied by the same constant. The constant varied from 1.0, base case, to 0.0, representing perfect prediction ability.

The percent hedge used in calculation of the VECC's is a measure of how conservatively the system is operated. The percent hedge is a scaling factor for the size of standard errors. The standard errors, when multiplied by the appropriate percent hedge constant, are subtracted from the forecasts of inflow (actual inflows) in every period. Therefore, increasing the percent hedge increases the margin of safety for refill and results in a more conservative operating policy. The percent hedge was varied from the base case 95 percent hedge to 99 percent, and down to a 75 percent hedge, by obtaining the appropriate multiple from a standard normal distribution table.

For each value of a parameter, 100 50-year regulations were run with the synthetic flows. Key operating characteristics were calculated for each regulation, including the number of years in which the reservoir failed to refill to 98 percent of its capacity, the size of the average refill failure, the number of months in which firm load failures occurred, the size of the average firm load failure, the average system generation over the 50-year planning period, the average July to December and January to June system generation, the average July to December and January to June secondary generation, the number of years in which the Water Budget release could not be met, and the size of the average Water Budget release deficit. As a verification of adequate flood control, the number of months in the second half of the operating year in which regulated outflow was greater than 600,000 cfs was calculated for each 50-year regulation. The effect of varying the three parameters on each operating characteristic will be discussed in the next sections of this chapter.

System Refill

The ability to refill the reservoir system is an important operating characteristic, because a failure to refill leaves the system vulnerable to firm load deficits the following year. A refill failure leads to a firm load deficit only when it is followed by a low flow year. Refill failures also adversely affect opportunities to use the river for recreation during summer.

The effect of varying the volume of the Water Budget release on the ability to refill the system is shown in Figure 9. The graph

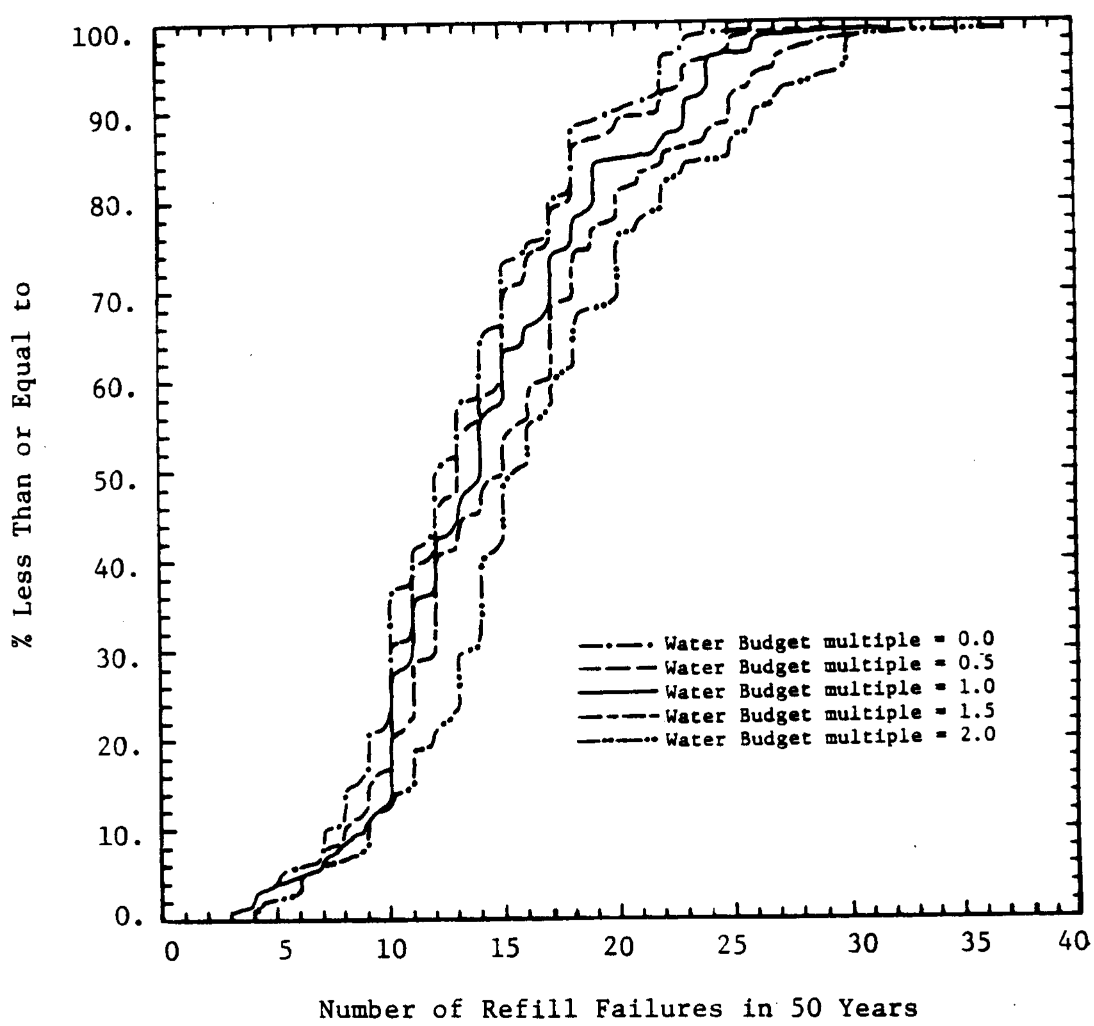

Figure 9. Effect of Volume of the Water Budget on Frequency of System Refill Failures

shows that as the volume of the Water Budget is raised from 0 MAF to 8 MAF, the number of years in each 50-year regulation in which the system does not refill to at least 98 percent of its capacity is increased. The effect of the Water Budget release is greater in low flow years, with a large number of refill failures, than in high flow years; the median of the distribution is affected more by increasing the volume from 0 MAF to 2 MAF than is the 10th percentile level, and less than the 95th percentile. Without the Water Budget, the maximum number of refill failures in any regulation is 26; with the Water Budget at 4 MAF, there is one regulation with as many as 32 failures; with the Water Budget at 8 MAF, one 50-year regulation has as many as 37 refill failures.

The effect of the Water Budget volume on the size of the average refill failure is displayed in Figure 10. A clear trend is exhibited here: as the size of the Water Budget increases, so does the size of the average refill failure. It is obvious from Figures 9 and 10 that increasing the Water Budget increases the frequency and magnitude of refill failures.

Figure 11 shows the effect of multiplying the standard errors of forecasted inflows uniformly by a constant ranging from 1.0 (base case) to 0.0. It can be seen from this figure that refill success is extremely sensitive to the size of the standard error; the failure rate is significantly larger when the multiple is lowered to 0.7 than for the base case. As the multiple is lowered from 0.7 to 0.0, refill failure rate is not affected. This is due to the lower bound on VECC's; the third year critical rule curve is used for this lower bound. Decreasing the size of the standard error used in calculating the VECC's lowers the VECC's until the lower bound is hit.

The cumulative distributions shown in Figure 12 must be analyzed in conjunction with those in Figure 11. The figures indicate that as the multiple of the standard errors is decreased from 1.0 to 0.7, the number of refill failures increases while the average refill failure decreases. The few failures that occur when the multiple is 1.0 are large failures occurring in years of extremely adverse water

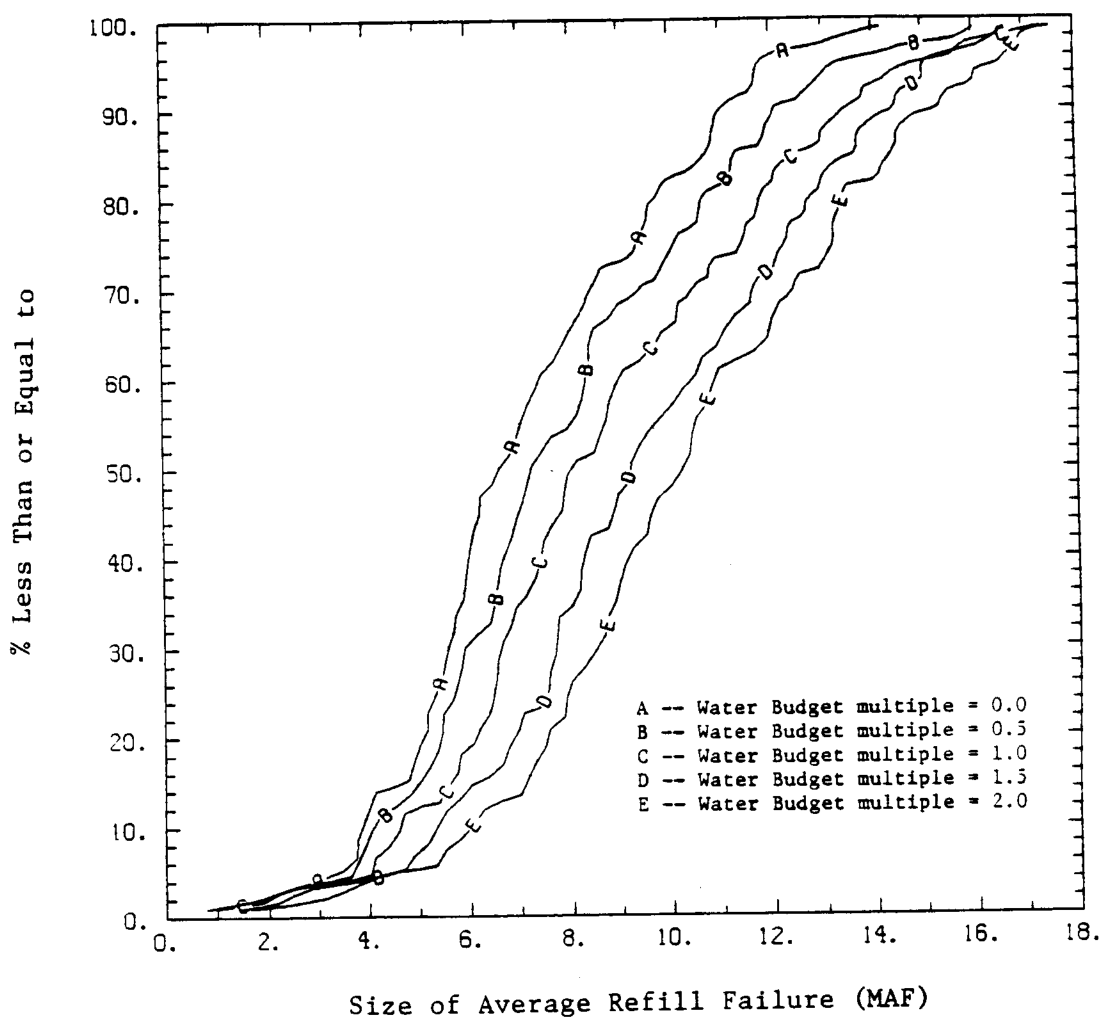

Figure 10. Effect of Volume of the Water Budget on Average System Refill Failure

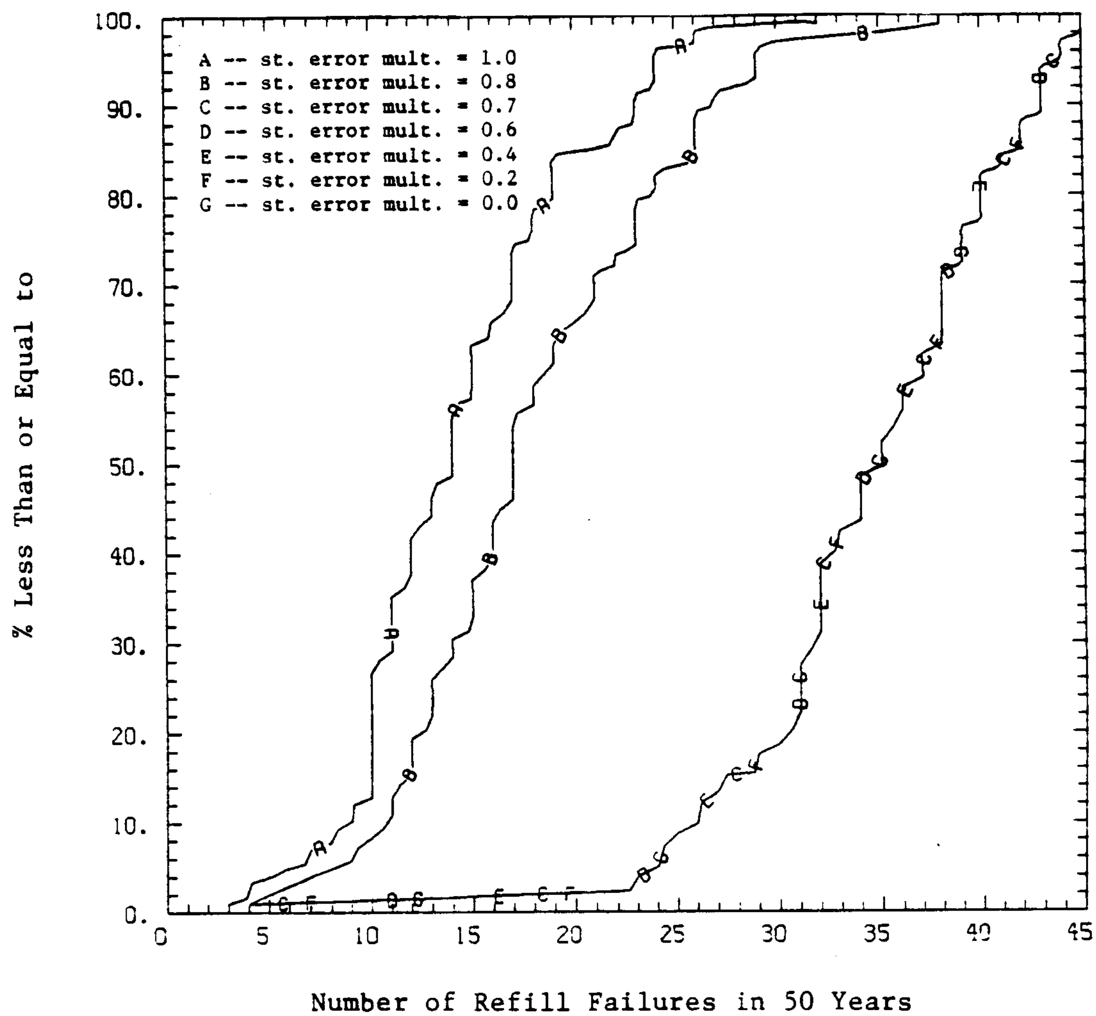

Figure 11. Effect of Size of Standard Errors on Frequency of System Refill Failures

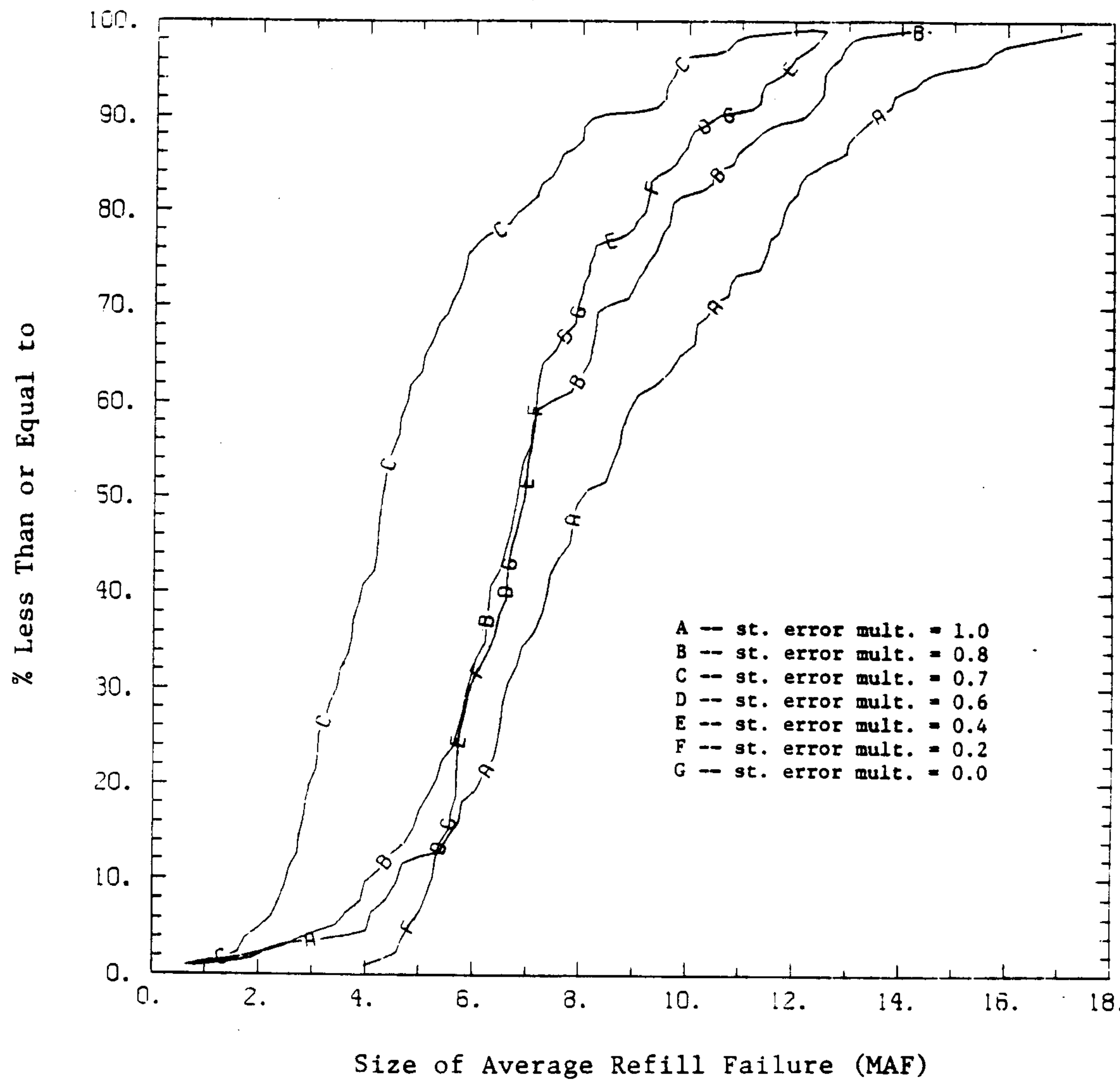

Figure 12. Effect of Size of Standard Errors on Average System Refill Failure

conditions. As the multiple is lowered to 0.7, the number of failures increases but the large failures are averaged over a large number of years and the average failure decreases (lines A to C). As the multiple is lowered further from 0.7 to 0.6, the number of failures remains the same while the magnitudes of the failures increase. Therefore, the average refill failure increases in size (see shift from line C to D). Figures 11 and 12 lead to the conclusion that decreasing the size of the standard errors increases the frequency and magnitude of refill failures.

Figure 13 shows that the effect of lowering the percent hedge is similar to decreasing the size of the standard errors. The percent hedge determines the size of the safety factor for refill; as the percent hedge is decreased, the VECC's are lowered. The graph shows that the 95 percent hedge currently used has essentially the same effect on refill as a 99 percent hedge. Using a 90 percent hedge significantly increases the refill failure rate; the median value for refill failure rate is 28 percent using the 95 percent hedge and 70 percent using the 90 percent hedge. Lowering the percent hedge from 90 percent to 75 percent has no further effect on refill failure rate, for the reason noted before; a lower bound exists for VECC's. Because varying the percent hedge and the size of the standard errors have precisely the same mechanism for effecting system operation, by raising and lowering the VECC's, only the results of varying the size of the standard errors will be discussed here.

Firm Load Failures

Figures 14 and 15 display the effect of varying the volume of the Water Budget on the frequency and magnitude of failures to meet firm power loads. The cumulative distribution functions for the number of months in which firm load failures occurred for several volumes of the Water Budget are shown in Figure 14. It is obvious that increasing the volume of the Water Budget from 0 MAF to 8 MAF increases the frequency of firm load failures. At the 50th percentile, a 4 MAF Water Budget causes three firm deficits which

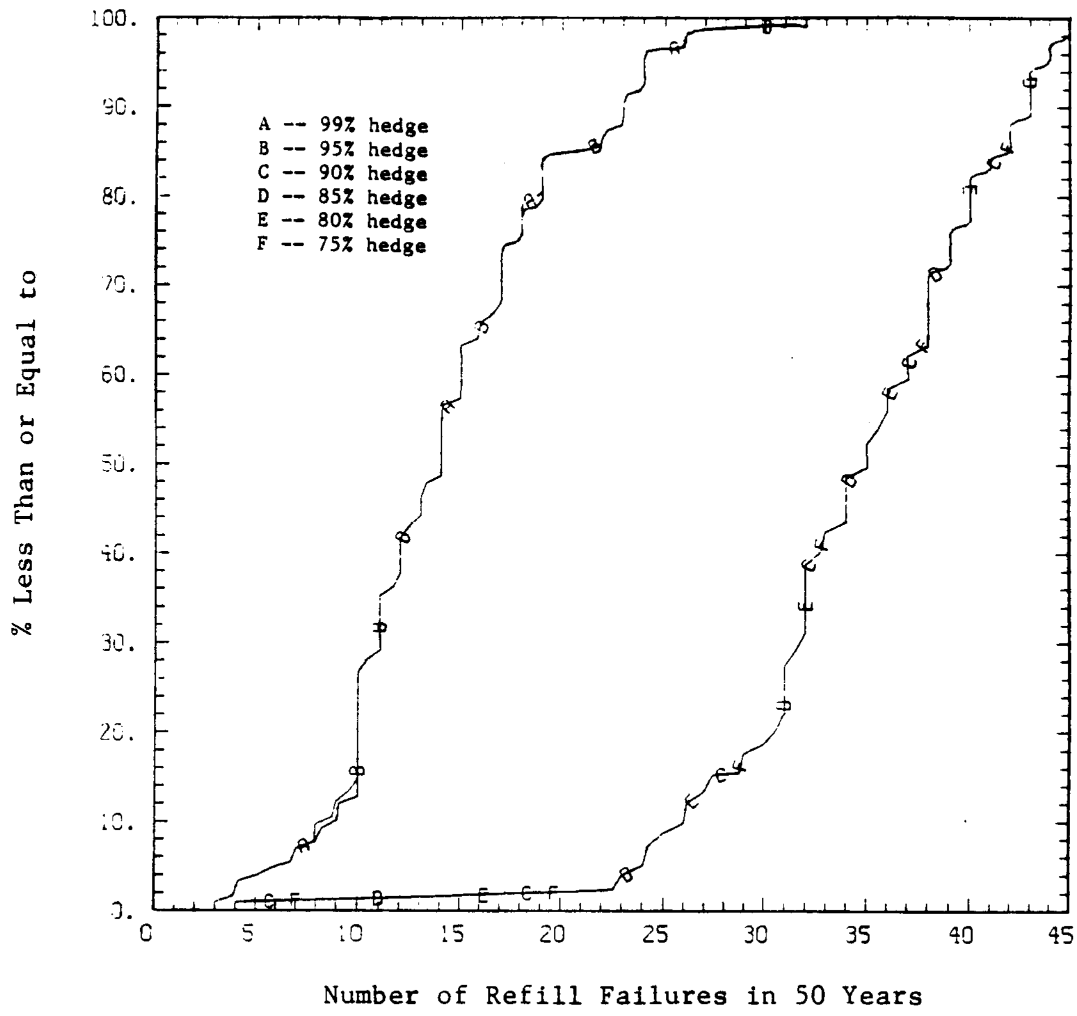

Figure 13. Effect of Percent Hedge on Frequency of System Refill Failures

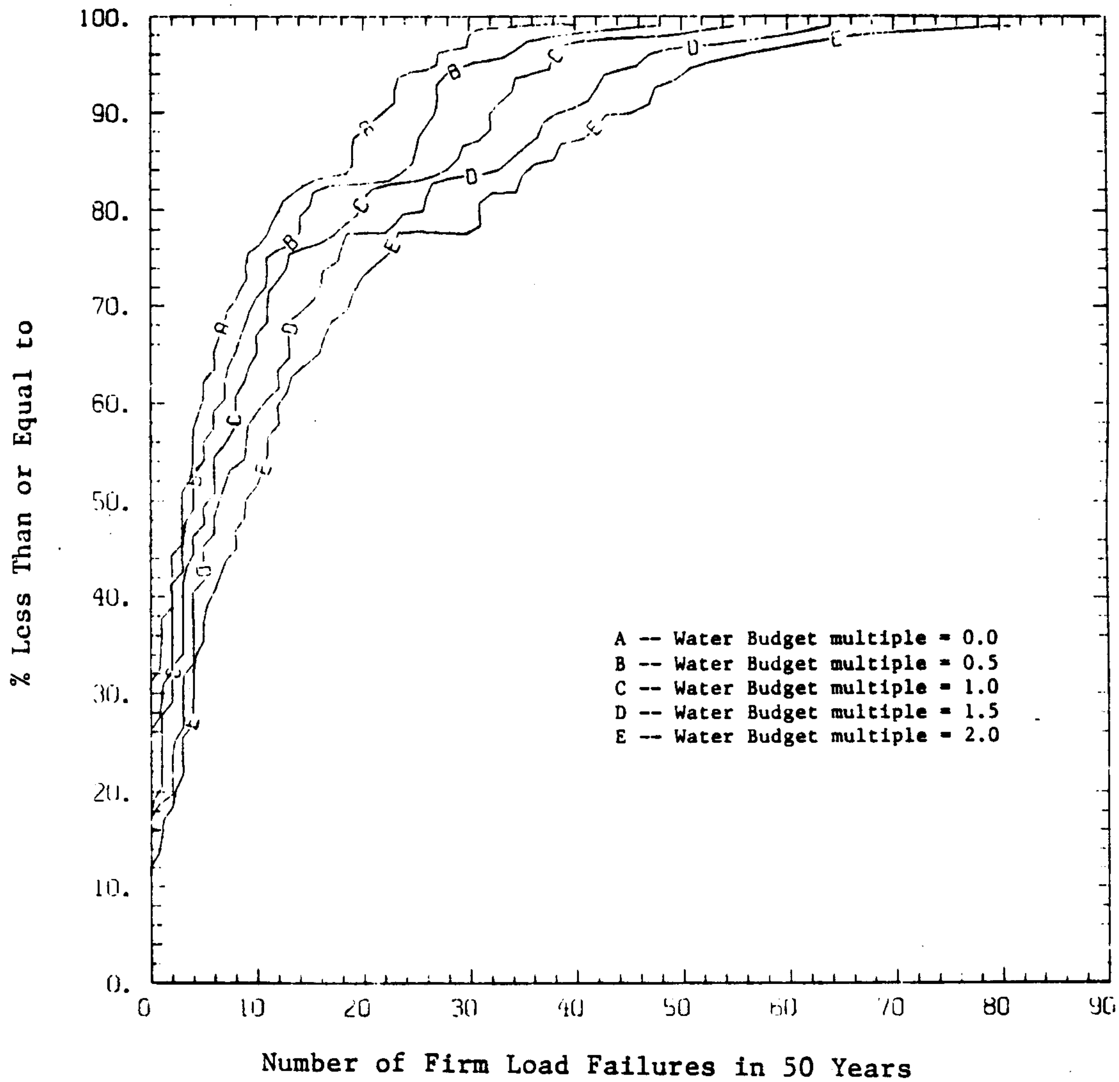

Figure 14. Effect of Volume of the Water Budget on Frequency of Firm Load Failures

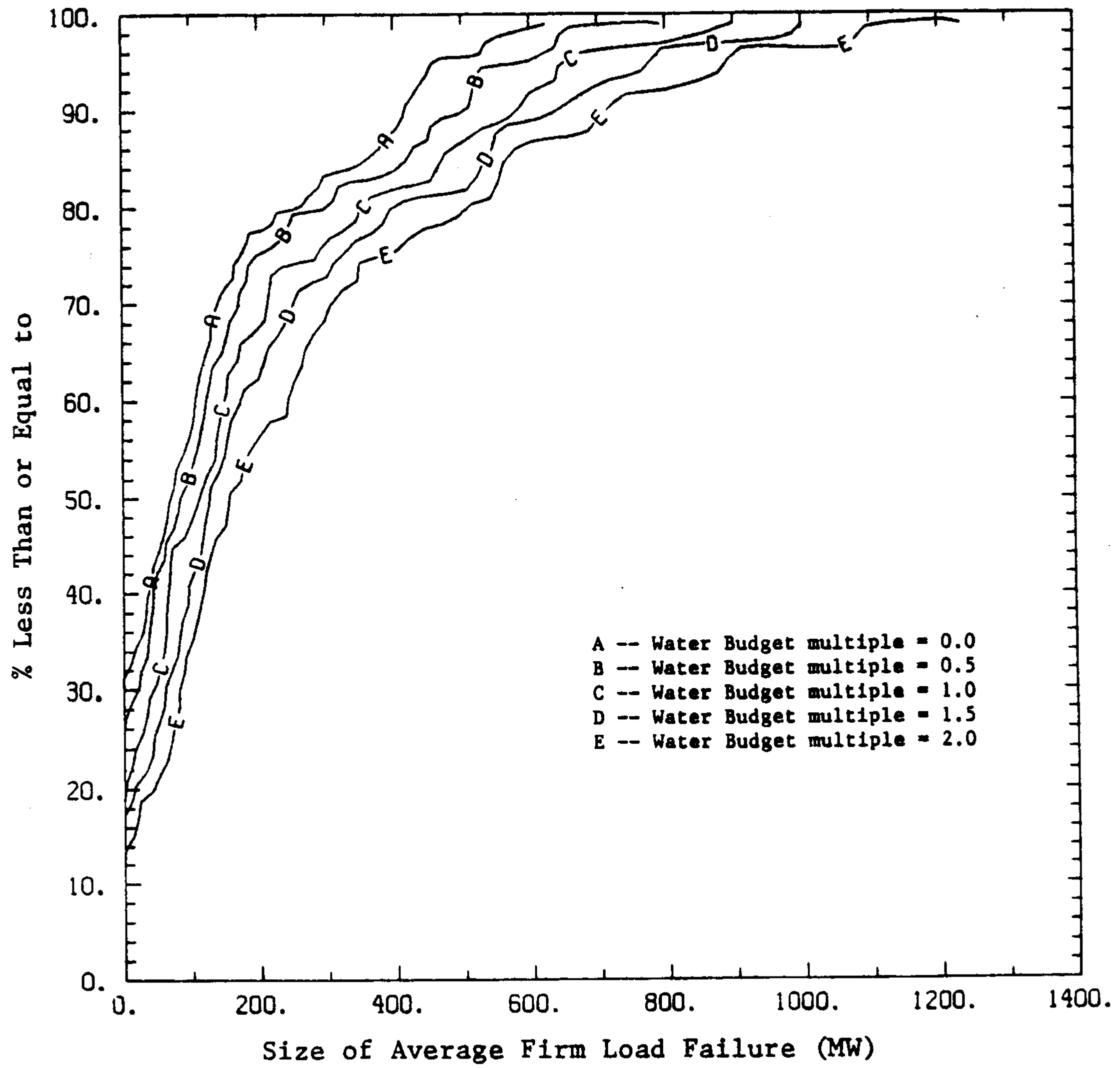

Figure 15. Effect of Volume of the Water Budget on Average Firm Load Failure

would not have occurred without the Water Budget. Increasing the volume further to 8 MAF causes three additional deficits. As expected, the effect is more pronounced in low flow sequences than in high flow sequences. Figure 15 displays the effect of the Water Budget on the size of the average firm deficit. The graph indicates that increasing the volume of the Water Budget increases the magnitude of the average firm deficit. At the 50th percentile, the 4 MAF Water Budget increases the size of the average deficit by approximately 40 MW; an 8 MAF Water Budget would increase the average deficit further by 45 MW.

Figures 16 and 17 display the effect of varying the size of the standard error on the frequency and magnitude of firm load deficits. Figure 16 indicates that assuming a smaller standard error leads to firm load deficits occurring more frequently, within the range of standard errors investigated here. The effect is more pronounced for low flow sequences than for high flow sequences (no firm load failures occurred in the highest 16 percent flow sequences for any size of standard errors assumed). At the 50th percentile, decreasing the multiple of the standard errors from 1.0 to 0.0 increases the number of months in which firm load failures occur by two. Figure 17 indicates that decreasing the size of the standard errors increases the average firm deficit (by approximately 30 MW at the 50th percentile going from a multiple of 1.0 to 0.0). It is interesting to note that, unlike the case of system refill failures, firm load failures are more sensitive to the volume of the Water Budget than to the size of the standard errors, within the ranges investigated.

Average Annual Generation Over 50 Years

One of the results reported by the Corps of Engineers in their series of alternative flow scenario studies was the effect on average annual generation over the 40-year record (U.S. Army Corps of Engineers, 1982). It was shown that slight reductions in average annual generation (approximately 50 MW) would occur as a result of the head loss resulting from lower reservoir elevations. To

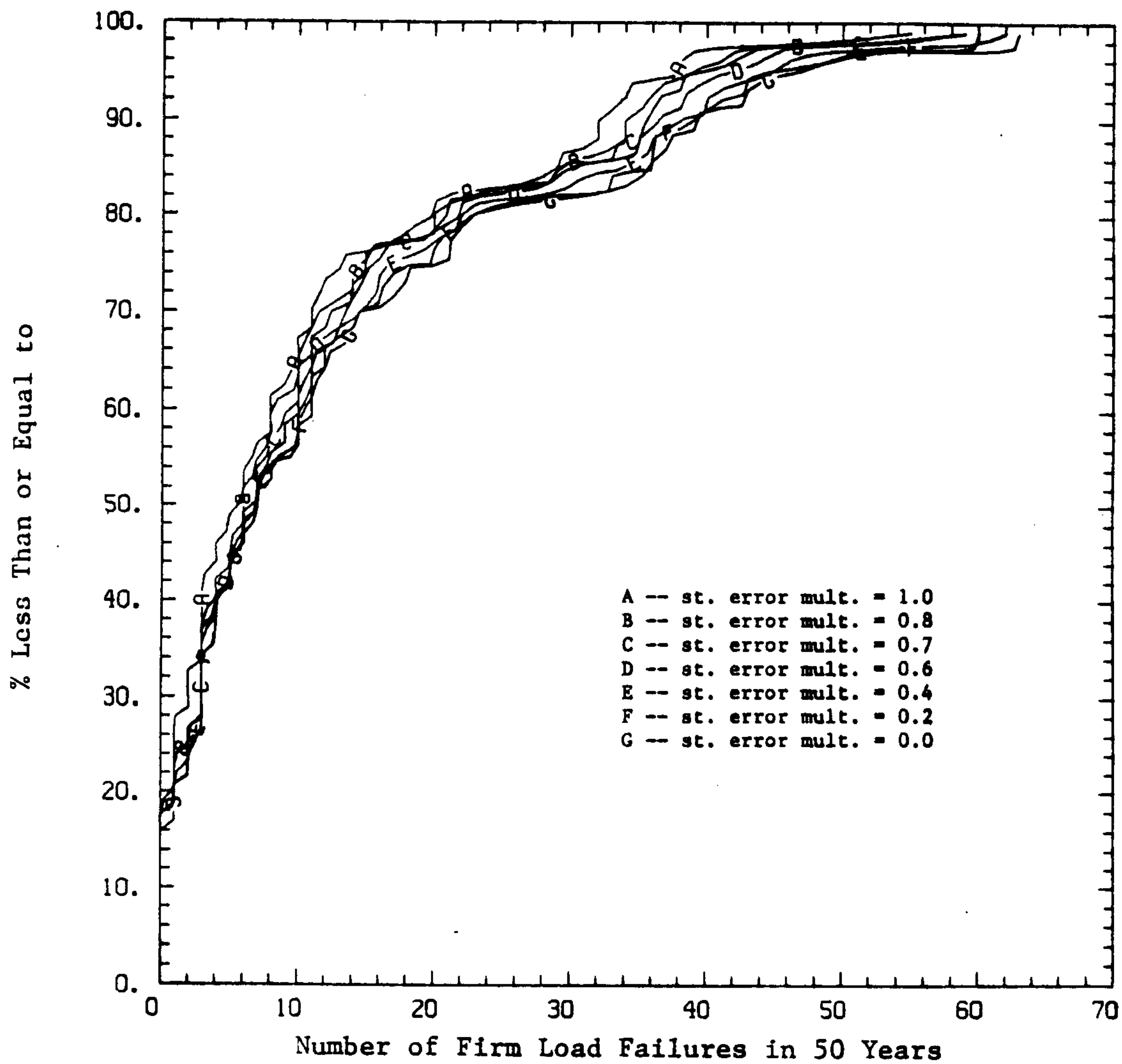

Figure 16. Effect of Size of Standard Errors on Frequency of Firm Load Failures

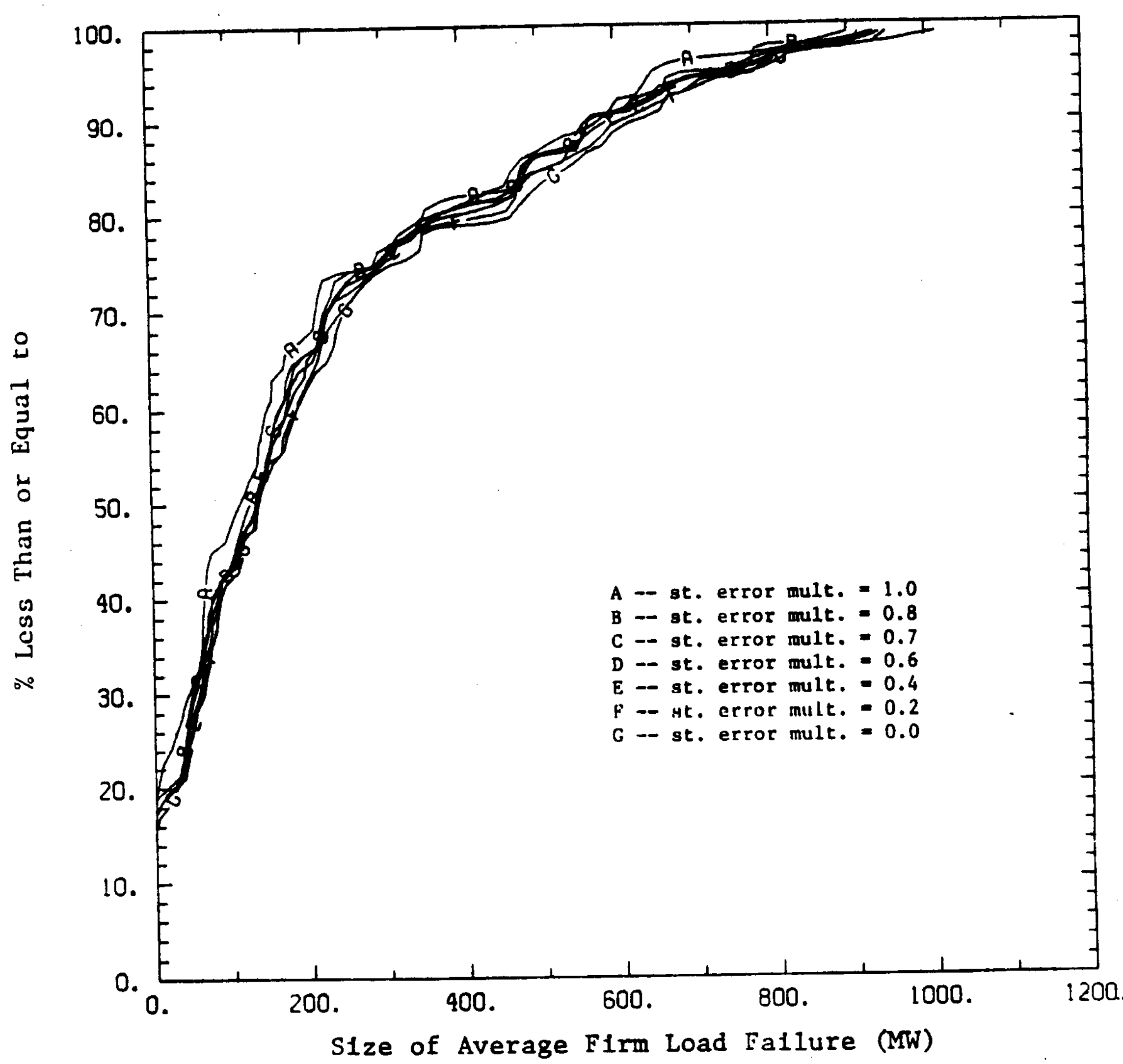

Figure 17. Effect of Size of Standard Errors on Average Firm Load Failure

determine whether the one-reservoir model would capture this effect, average annual generation was calculated for each Water Budget volume. To determine whether a similar effect could be produced by varying the VECC's, the size of the standard errors and percent hedge were varied also.

It can be seen from Figure 18 that varying the volume of the Water Budget has little effect on the average generation over each 50-year regulation; the median value for generation decreases by less than 100 MW in going from a 0 MAF to an 8 MAF release for the fish. The current Water Budget volume appears to cause less than a 50 MW decrease in average generation in all but the lowest flow sequences, and it seems to affect average generation more significantly in low flow sequences than in average to high flow sequences. During high flow years, secondary power produced from Water Budget releases would have been produced even without the Water Budget required release, because VECC's are lowered due to high probability of refill. However, during low flow years, the average annual generation is limited by the capability of the operators to shape the releases in an optimized pattern for hydropower. The Water Budget forces releases at a less than optimal time for hydropower generation (head is not at a maximum value during May).

Figure 19 displays the effect of varying the size of the standard error on average annual generation; as the size of the standard errors is increased, so is the average annual generation. As VECC's are lowered, refill is adversely affected, and less secondary energy is produced during the first half of the next operating year, when heads are higher than in the second half of the operating year. The average annual generation is more sensitive to this parameter than it is to the volume of the Water Budget. This is because this parameter affects the VECC's for every month in the second half of the operating year, while the Water Budget has no effect on May, June, or July VECC's. The Water Budget only affects the actual operation of the system during low flow years, when VECC's are binding. Note that lowering the multiple of the standard errors

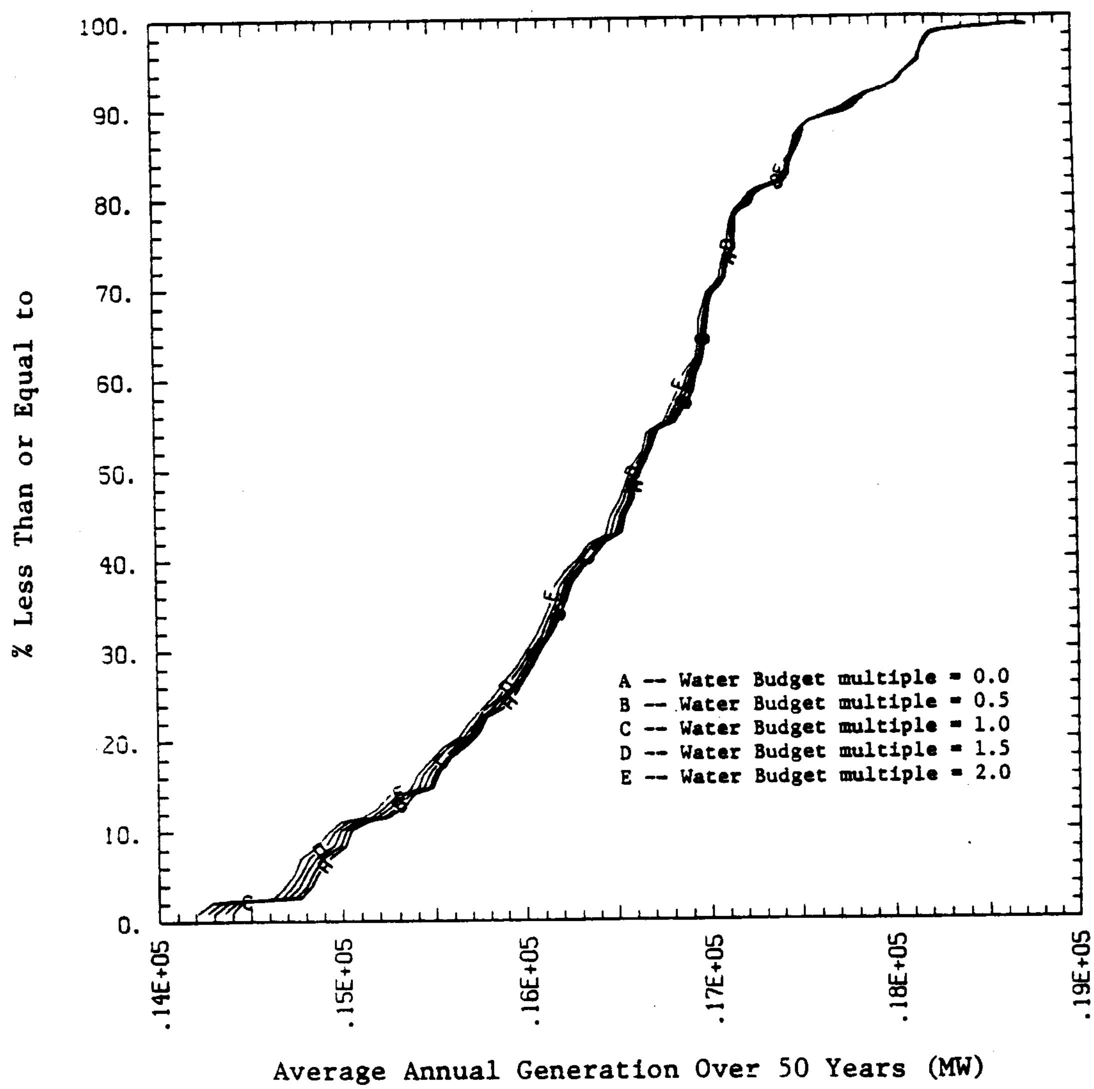

Figure 18. Effect of Volume of the Water Budget on Average Annual Generation

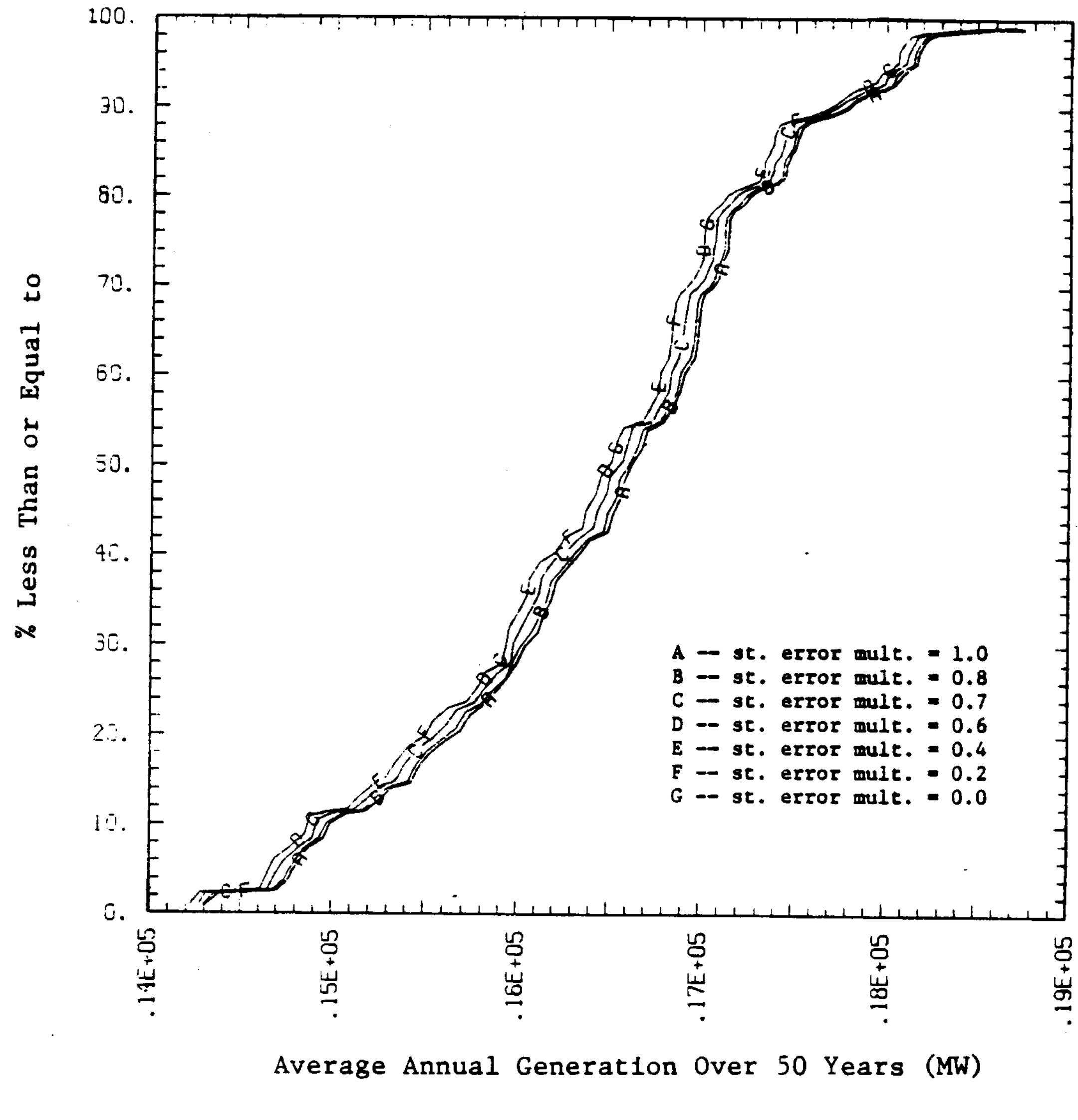

Figure 19. Effect of Size of Standard Errors on Average Annual Generation

past 0.6 has no effect on average annual generation; again, the lower bound on VECC's is binding. A similar effect is caused by increasing the percent hedge from 75 percent to 99 percent. As lower assumed standard errors lead to a higher refill failure rate and lower average annual generation, it would appear to be wise to assume the highest standard error.

The Effect of Eliminating the Lower Bound on VECC's

A series of runs was conducted to investigate the effect of eliminating the lower bound on the VECC's, since output parameters were shown to to be sensitive to this constraint (in the case of varying the size of the standard errors and the percent hedge). Figures 20 through 23 display the results of these runs, graphing the cumulative distribution functions for the number of refill failures and average annual generation.

Figures 20 and 21 show the effect of varying the multiple of the standard errors on the frequency of refill failures and the average annual generation. The multiple was varied from 2.0 to 0.0, to determine if the average annual generation would decrease when increasing the multiple from 1.0 to 2.0 (which might be caused by the necessity to spill in the first half of the operating year due to an overly conservative operation in the previous January to June period). Figure 20 indicates that removing the lower bound on VECC's causes the frequency of refill failures to increase for all multiples of the standard errors between 1.0 and 0.0 (refer to Figure 11 for comparison). As expected, the number of refill failures decreased as the multiple of the standard errors was raised from 1.0 to 2.0. Figure 21 displays the cumulative distribution functions for average annual generation. It can be seen that removing the lower bound on VECC's results in a decrease in average annual generation as the multiple of the standard errors is decreased from 0.6 to 0.0, an effect which was not present when a lower bound existed (refer to Figure 19 for comparison). A graph of cdfs for multiples 2.0 to 1.0 indicated that raising the multiple from 1.0 to 2.0 caused a further

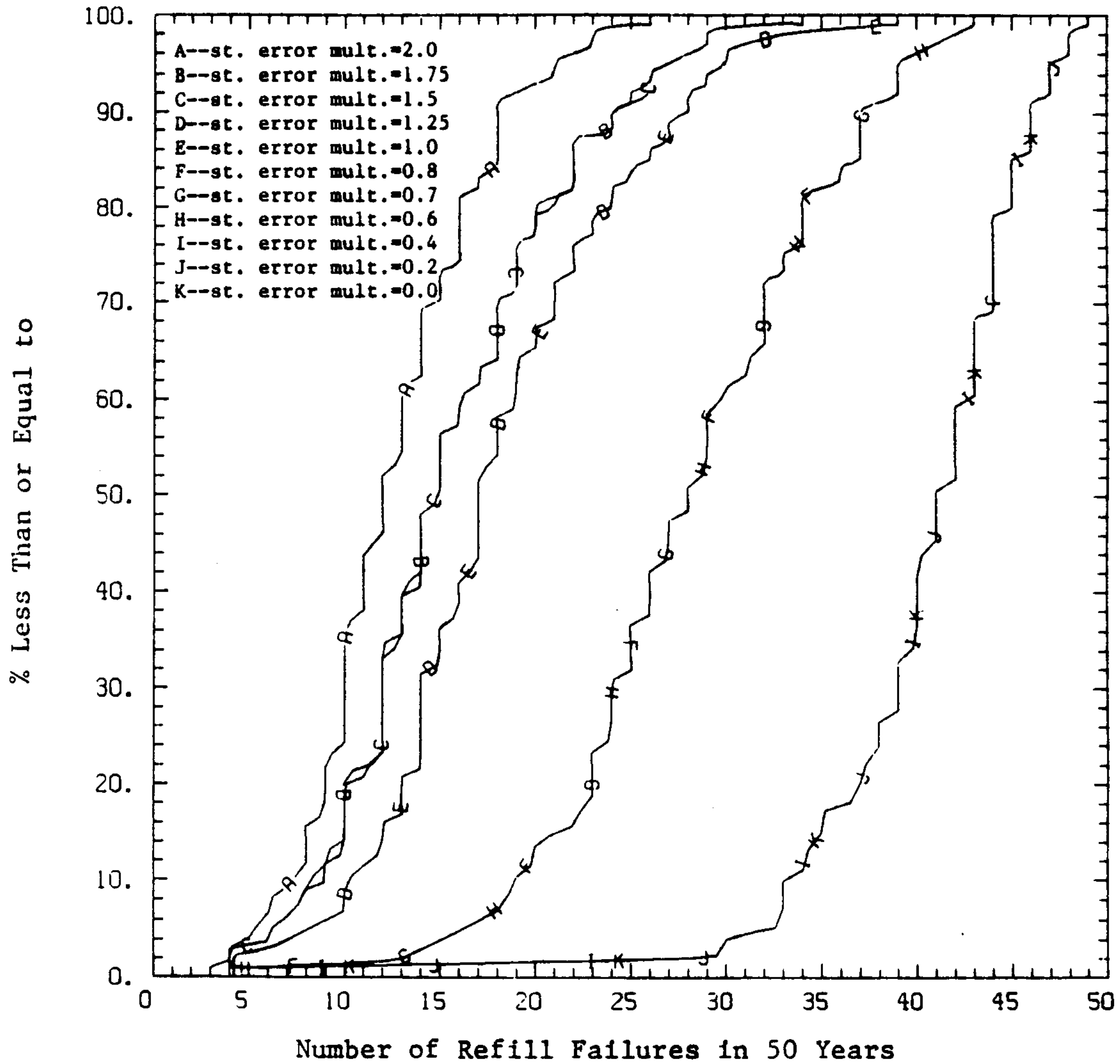

Figure 20. Effect of Size of Standard Errors on Frequency of Refill Failures in the Absence of a Lower Bound on VECC's

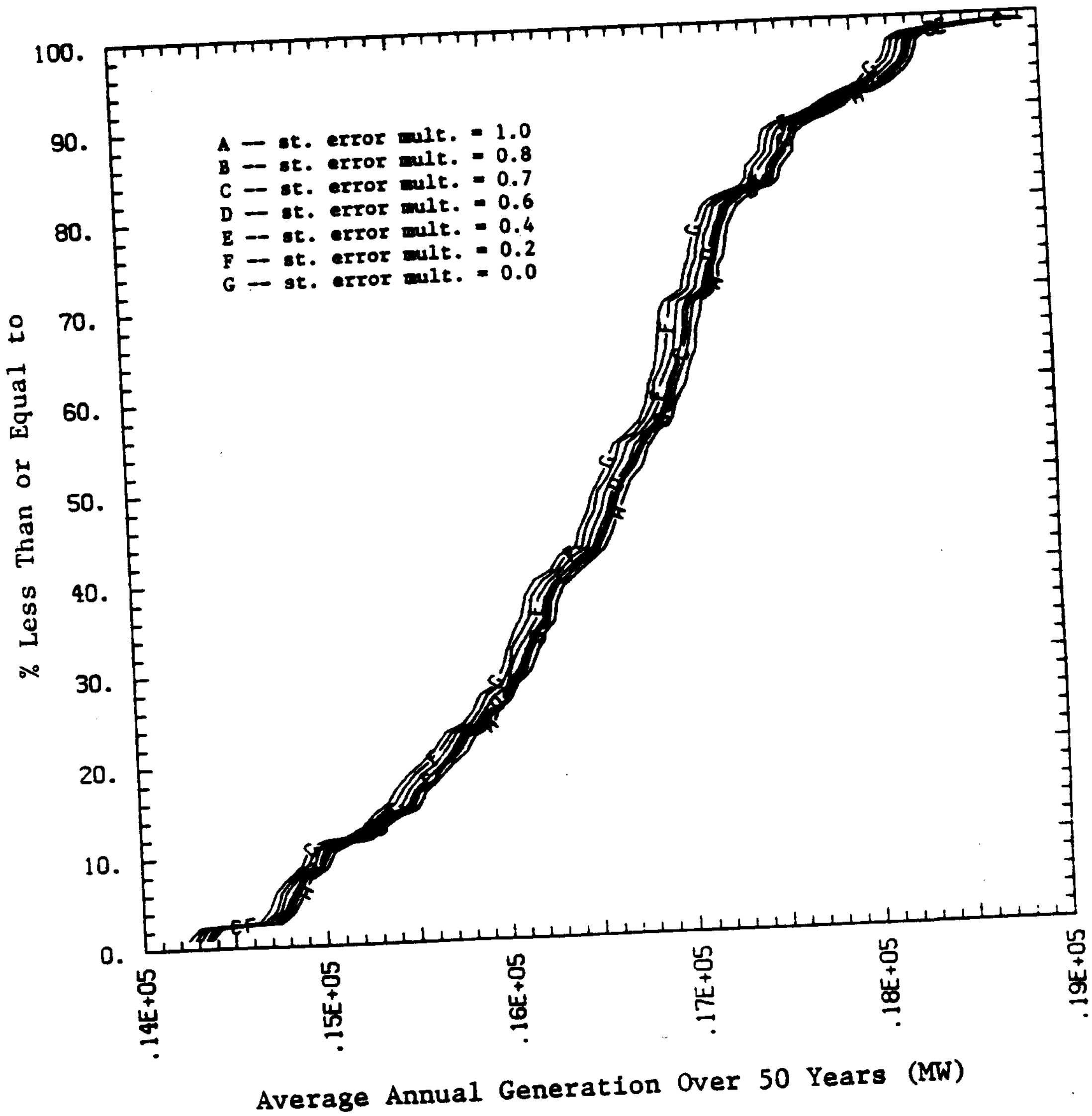

Figure 21. Effect of Size of Standard Errors on Average Annual Generation in the Absence of a Lower Bound on VECC's

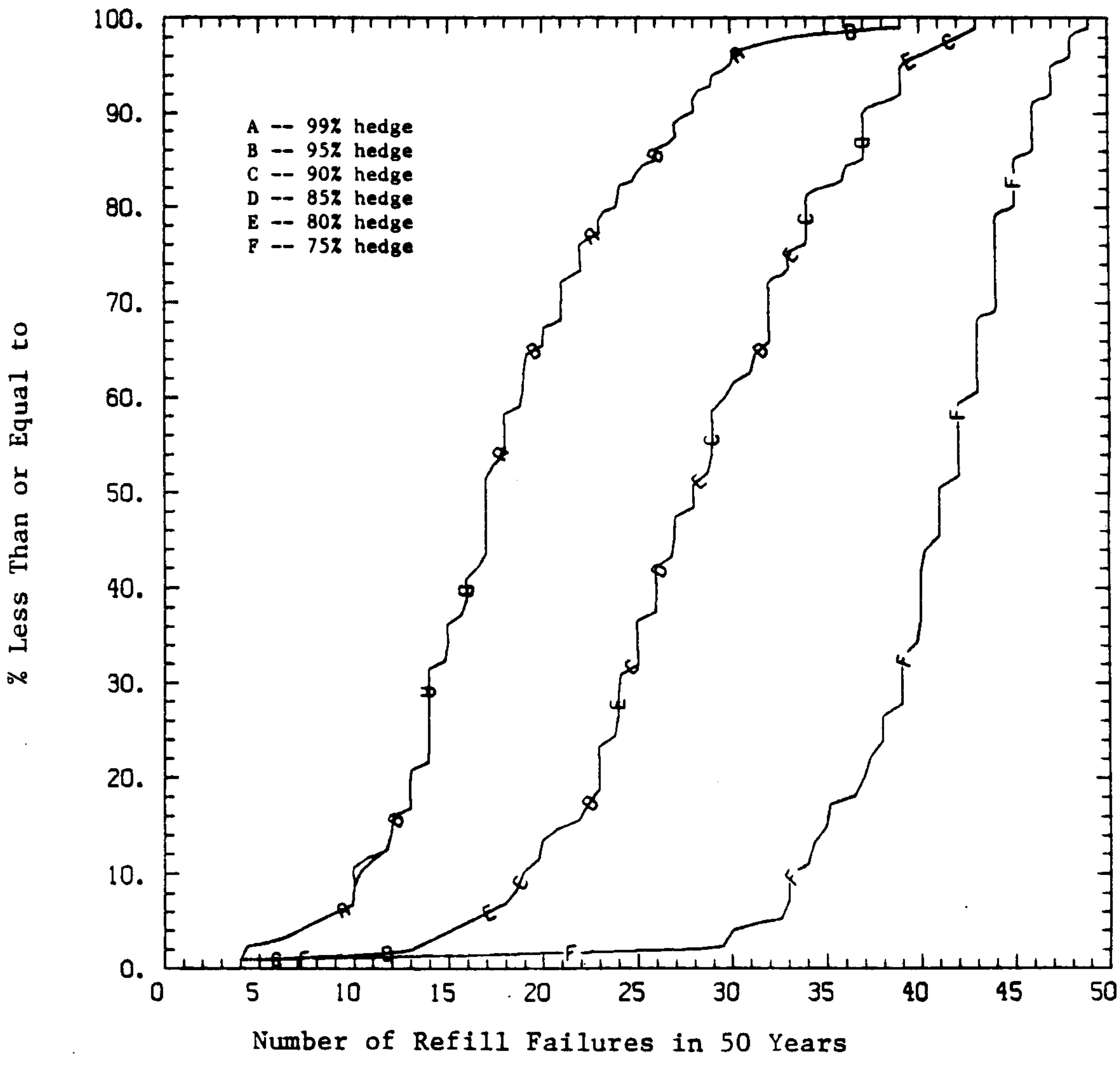

Figure 22. Effect of Percent Hedge on Frequency of Refill Failures in the Absence of a Lower Bound on VECC's

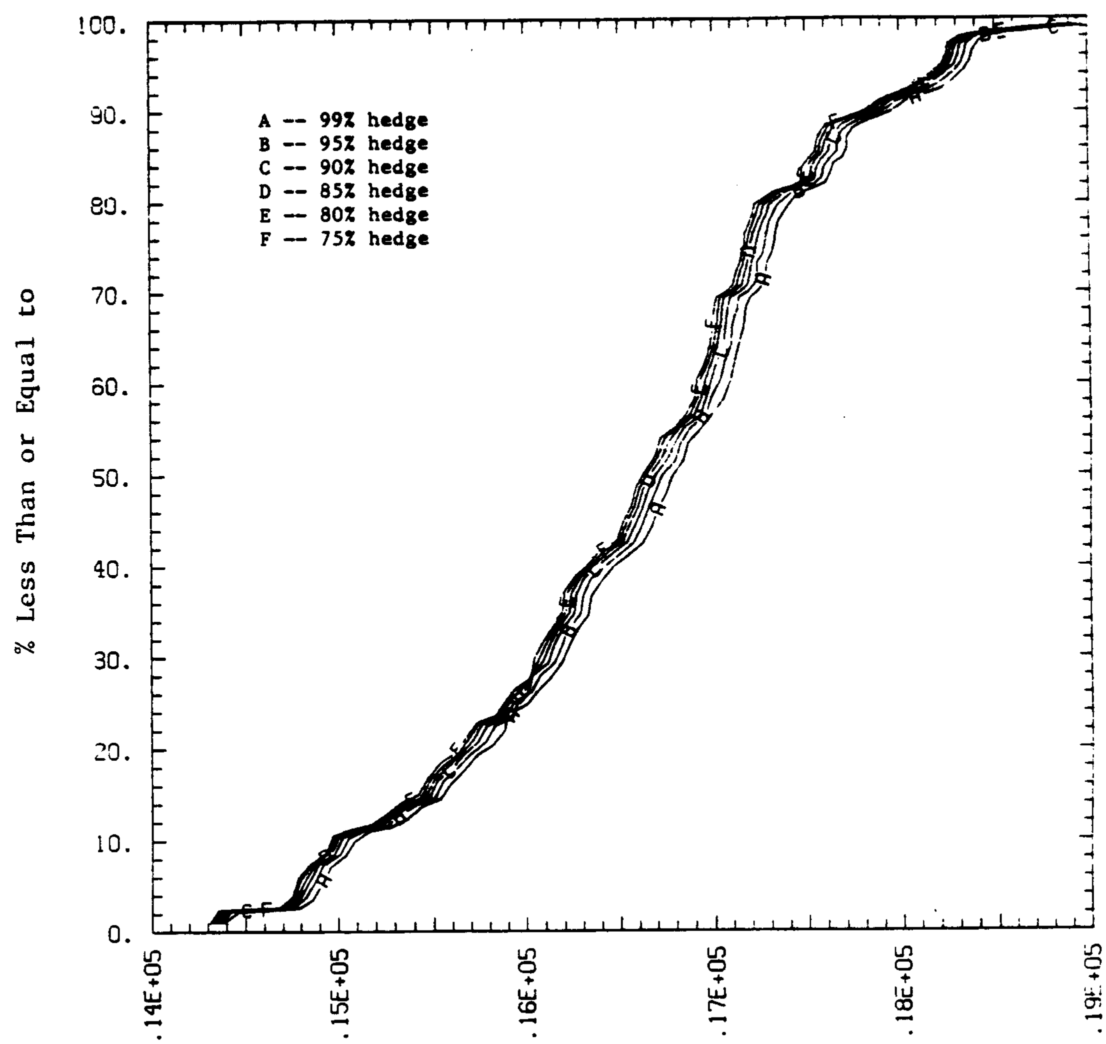

Figure 23. Effect of Percent Hedge on Average Annual Generation in the Absence of a Lower Bound on VECC's

increase in average annual generation, indicating that the spill constraint is not binding in the range of multiples investigated. Perhaps if the multiple was raised past 2.0, the constraint would limit average annual generation.

Figures 22 and 23 show similar effects from varying the percent hedge in the absence of a lower bound on VECC's. Cumulative distributions for the frequency of refill failures and average annual generation are shown for hedges from 99 to 75 percent. Comparing Figure 22 with Figure 13 indicates that removing the lower bound on VECC's increases the frequency of refill failures for each hedge factor. Figure 23 shows that as the percent hedge is increased, average annual generation is increased, as releases are postponed from the January to June to the next July to December period, where average head is higher. Comparison of Figure 22 with Figure 23 indicates that while several hedges may result in identical frequency of refill failures (Figure 22), their operation is not identical, as shown in Figure 23.

July to December and January to June Generation

Because the operating year is divided into two periods using different planning criteria, it was felt that varying parameters would have different effects in each period. Therefore, power generation statistics were tabulated separately for the two periods, and the results provided insight into trends in average annual generation.

Figures 24 and 25 show the effects of the Water Budget on average July to December total and secondary generation. Figure 24 leads to the conclusion that the Water Budget may influence total generation in the first half of the operating year. However, the decrease in total generation is only significant in average to low sequences (the greatest effect is a 400 MW decrease in going from 0 MAF to 8 MAF, and approximately a 200 MW decrease in going from 0 MAF to 4 MAF).

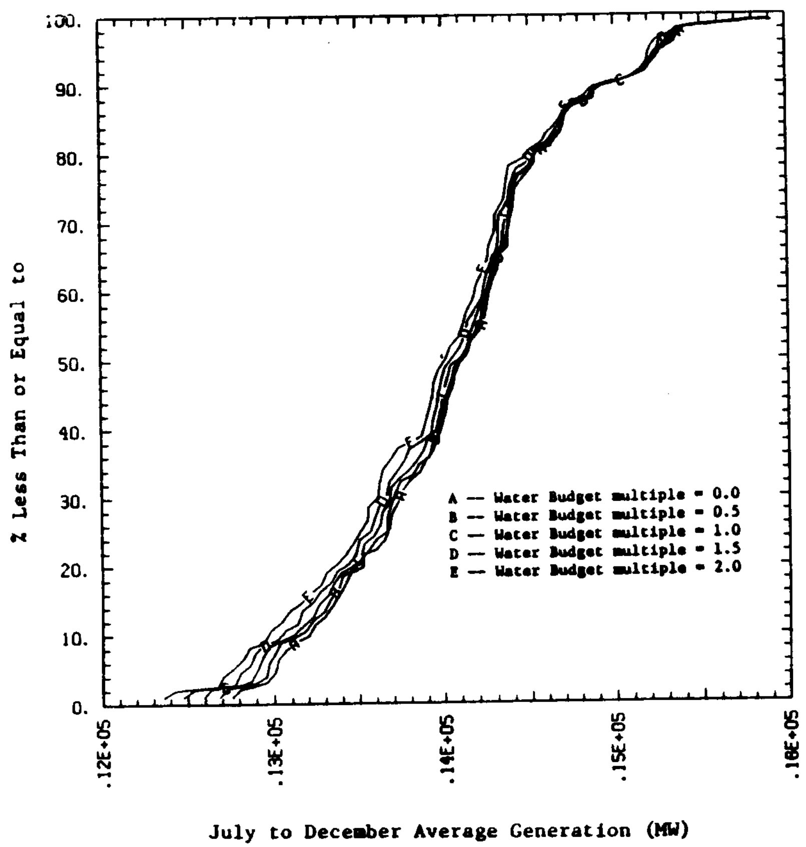

Figure 24. Effect of Volume of the Water Budget on Average July to December Generation

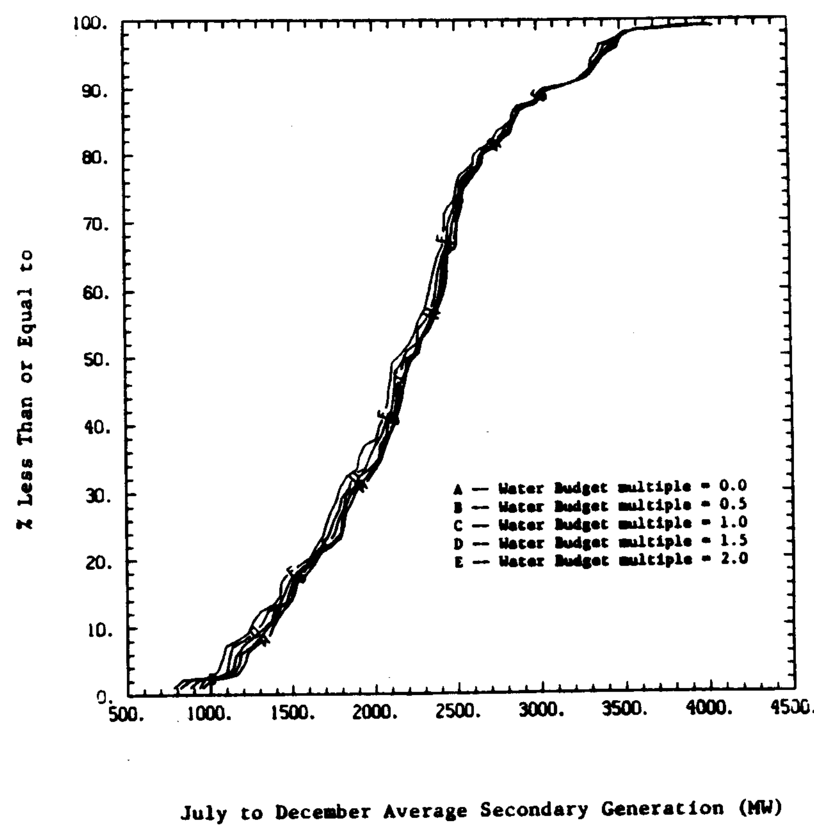

Figure 25. Effect of Volume of the Water Budget on on Average July to December Secondary Generation

Comparison of Figures 24 and 25 leads to another conclusion. The shape of the cumulative distribution functions for these two variables appear almost identical for each volume of Water Budget release. However, in the worst 8-10 sequences total generation is affected by more than just a decrease in secondary generation while going from a 0 MAF to 8 MAF Water Budget release. In these sequences, firm load is affected also by approximately 100 average MW for the most severe sequence.

Figures 26 and 27 show the results of Water Budget release volumes on total and secondary generation during the second half of the operating year. Figure 26 shows that varying the Water Budget release has no significant effect on total generation during the second half of the operating year and indicates that in all but the lowest flow sequences, the Water Budget will have no effect on the amount of secondary energy produced during this period. In low flow sequences, the Water Budget will cause slightly more secondary energy to be produced during this period than would be generated without the Water Budget.

Figures 28 through 31 show effects on the same variables as a result of lowering the size of the standard errors used in the model. Figure 28 indicates that as the multiplier of the standard errors is decreased from 1.0 to 0.6, July to December average total generation decreases significantly. Comparing the shape of the two CDF's for each value of the multiplier demonstrates that the effect on total generation is entirely explained by the secondary generation change during this period. This is related to the mechanism of the ECC's and VECC's as calculated in the model. As the standard errors are decreased, the VECC's used in the second half of the generating year are lowered. This lowering of the VECC's for January to December causes refill to be adversely affected, and consequently the following year's operation will be dependent on this year's operation. The reservoirs will be drafted below the ECC after firm loads are released and no secondary energy will be produced. This explanation is supported by the observation that during high flow

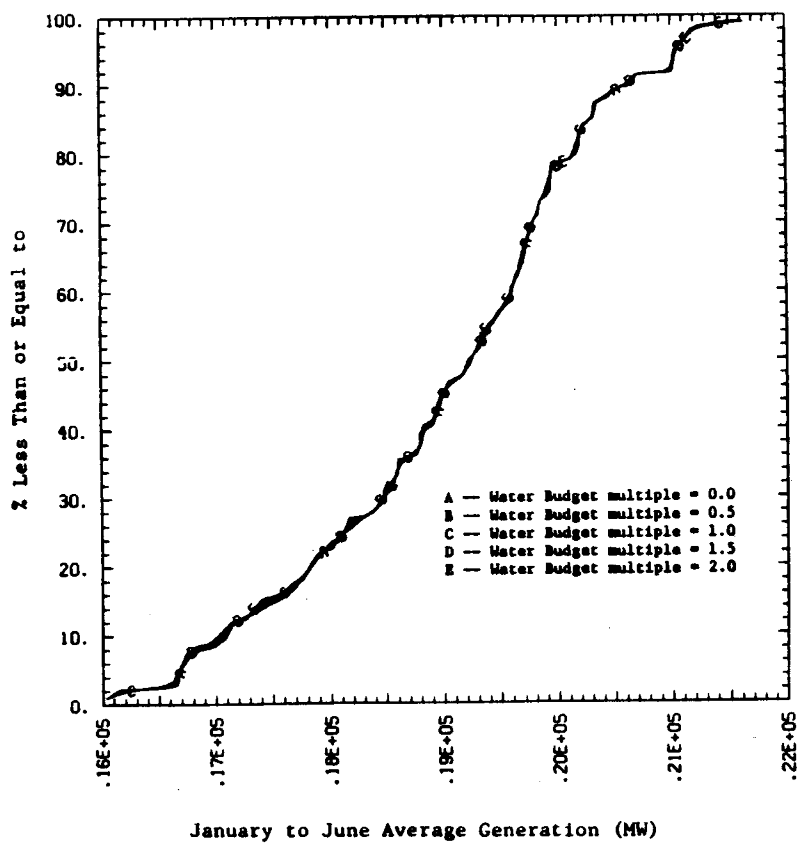

Figure 26. Effect of Volume of the Water Budget on Average January to June Generation

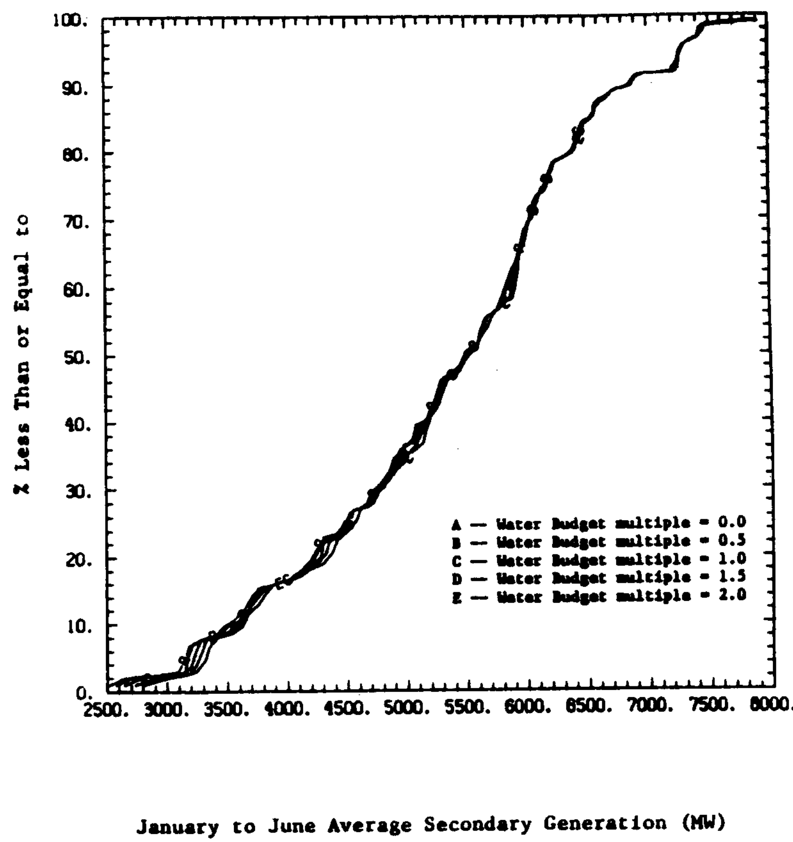

Figure 27. Effect of Volume of the Water Budget on Average January to June Secondary Generation

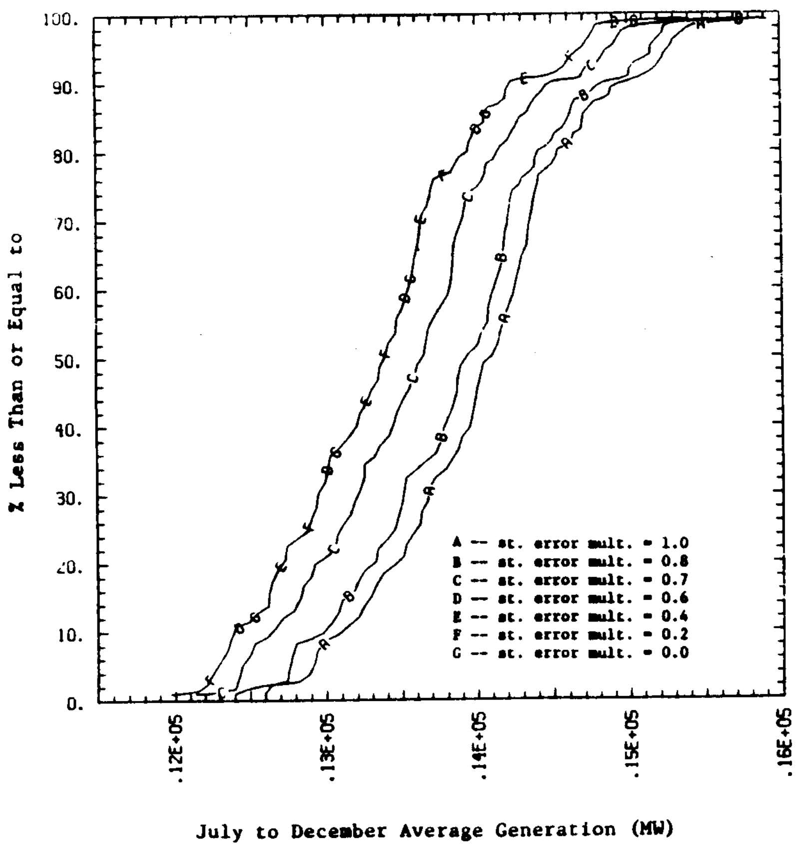

Figure 28. Effect of Size of Standard Errors on Average July to December Generation

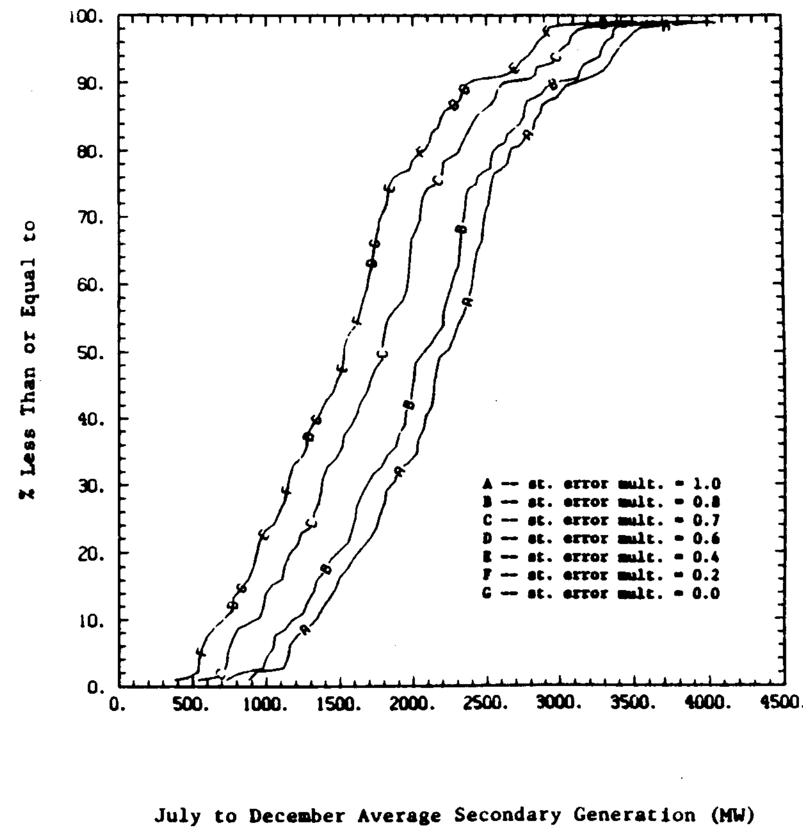

Figure 29. Effect of Size of Standard Errors on Average July to December Secondary Generation

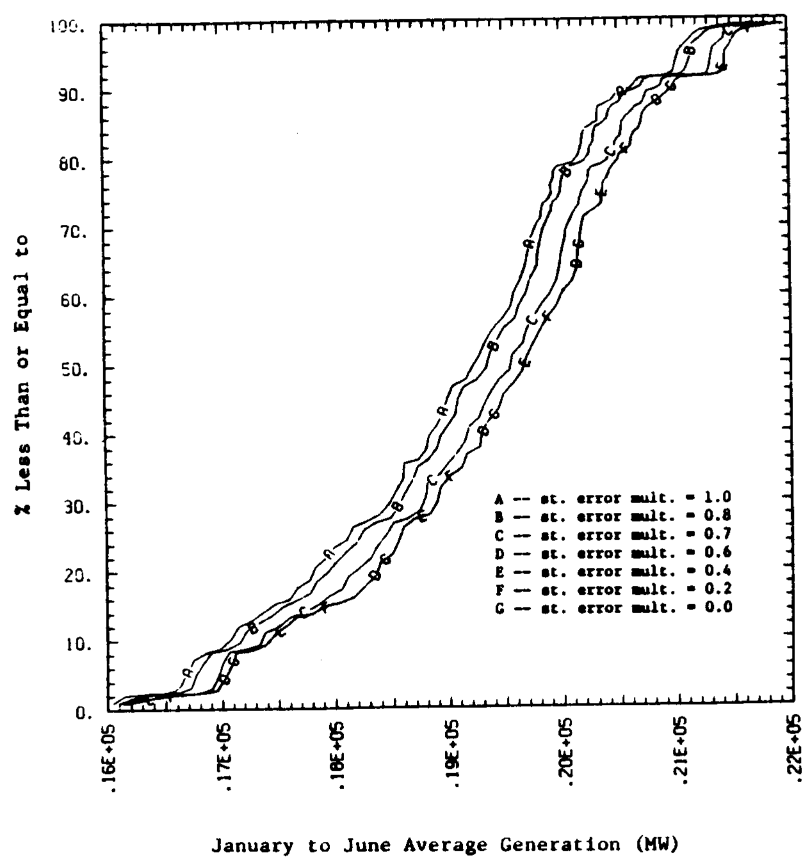

Figure 30. Effect of Size of Standard Errors on Average January to June Generation

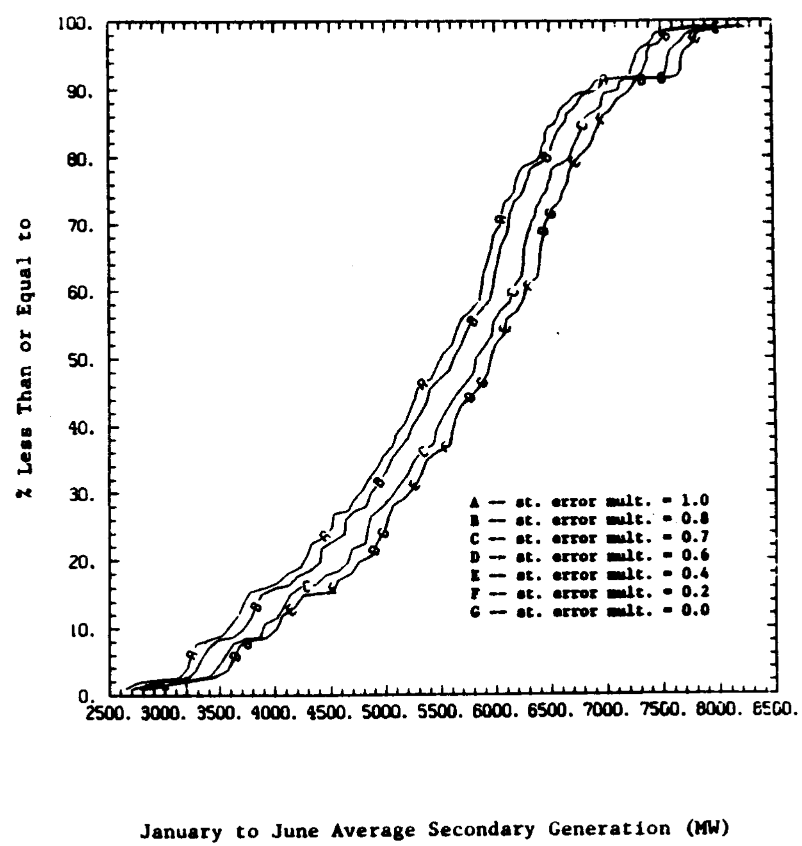

Figure 31. Effect of Size of Standard Errors on Average January to June Secondary Generation

sequences, when refill failure rate would be extremely low, the effect is not present to as great a degree. In these sequences, July to December operation is not affected by the preceding year's January to June operation.

The trend in generation in the January to June period from varying the multiplier of the standard errors is exactly opposite to the trend noted in Figures 28 and 29. Figures 30 and 31 lead to the conclusion that as the size of the standard errors is decreased, more secondary power is produced in this period. Firm power is not affected at all. This can be seen by comparing the two CDF's for each value of the multiplier. Similar trends result from varying the percent hedge. These system characteristics are more sensitive to the size of the standard error than to the size of the Water Budget.

Water Budget Misses

Figure 32 displays the cumulative distribution functions for the number of years within each 50-year regulation in which the Water Budget requirement was not satisfied for several multiples of the standard errors. It is obvious that satisfying the Water Budget release is possible in all but the lowest flow sequences. In the worst of the 100 sequences, the Water Budget was not satisfied in 3 years out of 50. Lowering the standard errors results in more sequences with at least 1 miss occurring, but this effect is reduced in the worst flow sequences, where the misses might have occurred regardless of storage regulation. As the standard errors assumed are decreased, operation is less conservative during the second half of the operating year and there is less water available for the Water Budget release.

Figure 33 shows the effect of the magnitude of the standard errors on the size of the average Water Budget deficit. It is clear from this graph that in all but the worst flow sequences, assumption of a smaller standard error increases the average Water Budget release deficit. In the worst 5 percent of the sequences, the size of the standard errors has no effect on the average Water Budget

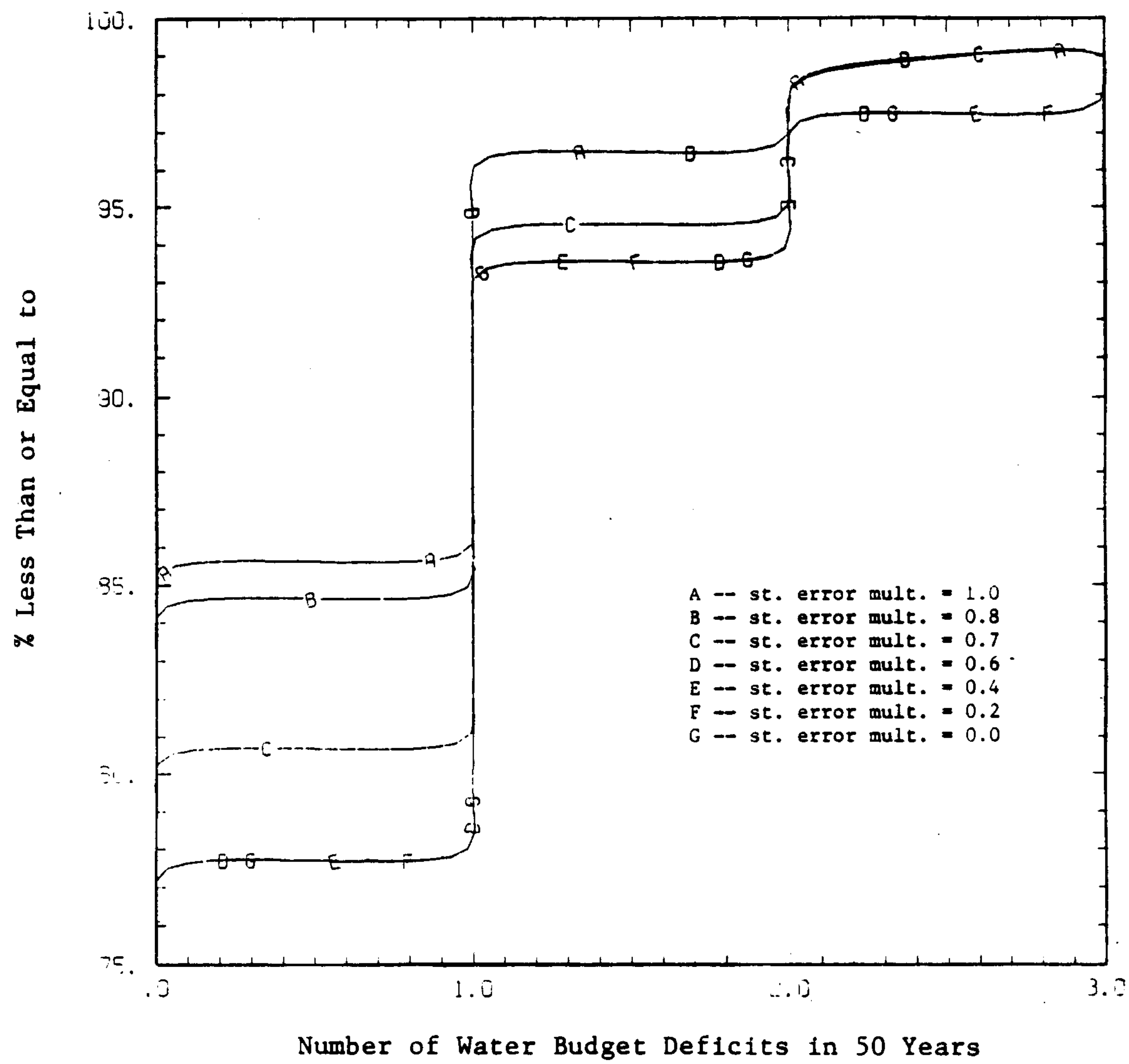

Figure 32. Effect of Size of Standard Errors on Frequency of Water Budget Misses

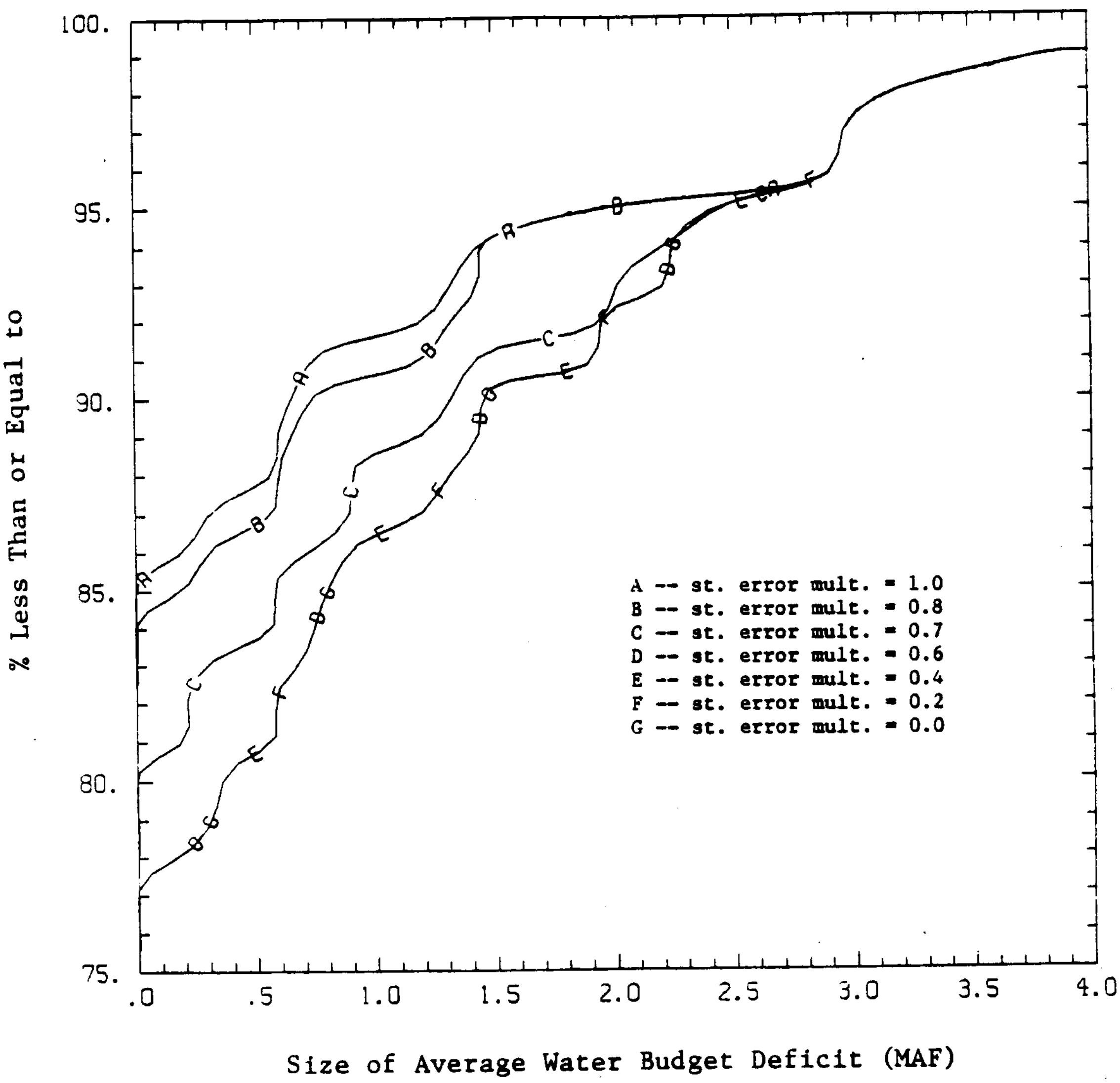

Figure 33. Effect of Size of Standard Errors on Average Water Budget Miss

deficit. Figures 32 and 33 indicate that decreasing the standard errors increases the frequency and magnitude of Water Budget deficits in low to average flow years.

Summary

The use of the one-reservoir model proved to be a valuable method for investigating the effect on the power generating capabilities of the system resulting from various operations and planning scenarios. Comparison of results of 40-year studies with those obtained by the Corps using HYSSR showed that the model accurately estimates average annual generation, as well as July to December average generation and January to June average generation. Varying the volume of the Water Budget release and running 100 regulations with each volume indicated general trends over a broad range of flows. The model effected a savings in computer resources over those required by the complex hydroregulator models, for execution of the program on a CDC Cyber 750 requires 18 CPU seconds for 100 50-year regulations.

The results of the synthetic flow studies indicate that the Water Budget would have an adverse impact on the ability of the system to refill, and to satisfy firm load demands, on average annual generation, and July to December average generation. However, these effects are relatively minor when compared to the results that can be achieved by operating the system under a less conservative operating policy or assuming improved forecasting ability. This effect is achieved by decreasing the size of the safety factors used in calculating VECC's, either by lowering the values assumed for the standard errors of the forecasted volume inflow or by lowering the percent hedge from 95 percent to 90 percent.

Note on Interpretation of Standard Error Results. Results of varying the size of the standard errors draw attention to an important limitation of CRISP; it is not an optimization model. CRISP runs in one mode only: run-to-rule curves. The system simulated operates with first priority being firm power generation. System refill is given priority over generation of secondary power. No attempt is made to maximize average annual generation. Were CRISP an optimization model, system refill would not have priority over production of secondary energy. The effects of varying the multiple of the standard errors would be expected to differ; decreasing the multiple of the standard errors would not necessarily result in greater production of secondary generation during the January to June period. Instead, the releases would be postponed until head/efficiencies were maximized. It is expected that decreasing the multiple of the standard errors would result in increased average annual generation, as there would be fewer constraints on system operation.

The next chapter concludes this report with a discussion of the value of the one-reservoir model as compared with other models. Insights from the development and use of CRISP are drawn upon to make recommendations of appropriate levels of complexity for future efforts in modeling the conflict between power and fish production.

CHAPTER 7

Conclusions and Recommendations for Future Modeling Efforts

This chapter presents a summary of the significant results of this study. Conclusions are drawn from the results of the model review, interview process, and computer experiments. Recommendations are made for future modeling to enhance management efforts.

Summary of Results

1. Hydroregulator (HR) models currently used to evaluate trade-offs between hydropower production and fish production in the Columbia River Basin incorporate a high degree of complexity. In lieu of an accepted measure of computer simulation model complexity, indirect indicators of model complexity were used to characterize the models reviewed. These indicators include the size of the model as indexed by the length of computer code, the execution time of the program, storage requirements for execution, the number of modes of operation, the processing complexity of the program, and degree of model familiarity required for appropriate use.

2. The complexity of these models hampers multi-agency participation in the decision-making process. Representatives of the agencies using the HR models indicate that one to two years of familiarity with the models is necessary before the models can be used properly (see Appendix). Therefore, potential users of the models are limited to those who have the time to become very familiar with the programs. There are very few such users outside the agencies maintaining the programs. The fisheries agencies, in particular, must rely upon the results of studies conducted by agencies responsible for regulating

the flows for the purposes of hydropower and flood control, using models originally designed for those specific purposes.

<u>3. The complexity of these models is inappropriate for conflict management.</u> Personnel in the agencies using the HR models feel that their models are appropriate for investigating the conflict between fish and hydropower production. In light of the problems introduced into the decision-making process by the complexity of these models, a fair evaluation of the appropriateness of these models for conflict management must address the following questions: Do the models accurately estimate the values of critical output parameters? Are they the least complex models which are capable of estimating these parameters to an acceptable accuracy (i.e., are there no simpler models which could be developed which would lead to the same decision)? The nature of the problem experienced by anadromous fish on the river requires that any computer simulation model used to investigate alternative solutions be capable of regulating the river to meet proposed fish flow schemes. The HR models are capable of regulating flows at various control points in the system to meet alternative flow scenarios and of estimating the effect of these scenarios on power generation. The question remains as to whether they are the simplest models possible to fulfill this purpose. Personnel using these models have indicated that many plants in the system which do not significantly affect the regulation of the river or system generation are included in the models (see Appendix). They have suggested methods by which a simpler model could be developed which would still be capable of regulating flows and estimating impacts to power generation.

<u>4. One-reservoir models with monthly power generation functions are sufficiently complex to estimate average annual energy accurately, as well as July to December and January to June average energy.</u> To demonstrate the potential of a simplified HR model for conflict management and to identify methods by which variables in the complex

HR models could be aggregated, a composite reservoir with the storage capacity of the Coordinated System was simulated. The model (CRISP) incorporated the Northwest Power Planning Council's Water Budget into operations and annual planning. Comparison of results of 40-year regulations with results from two studies done by the Corps of Engineers for the Instream Flow Work Group using one of the HR models (HYSSR) indicates that CRISP accurately estimates average annual generation, as well as average July to December and January to June generation over the 40-year historical record of flows.

5. Increasing the volume of the Water Budget has modest impacts on system refill, secondary generation from July to December, and average annual generation. The results of the synthetic flow runs indicate that the Water Budget causes increased generation in the second half of the operating year at the expense of generation from July to December.

6. System operating characteristics are more sensitive to the the size of the safety factor used in calculating refill rule curves than to the volume of the Water Budget. This implies that the standard error assumed for the forecast inflows and the percent hedge are critical input parameters, and that attention should be given to modeling these parameters accurately.

7. A simplified model with the capability to regulate flows would be a valuable addition to the collection of models now used to manage the fish and hydropower conflict on the Columbia River. It would enable the agencies to investigate the interaction between the parameters controlling the fish population and the relative importance of each parameter, while estimating the impacts of proposed solutions to the problem. Moreover, it would be an improvement over the existing models' abilities to analyze the biological aspect of the conflict, as well as an improvement in

processing complexity, user-friendliness, and a savings in computer resources.

Recommendations

It would be inappropriate for the agencies using the HR models to lower the complexity of their models to address the needs of the fisheries agencies. Indeed, the complexity of these models is appropriate for their original purpose; neither BPA nor a private utility could base their contracts for energy on the results of a one-reservoir model. However, support exists within the fisheries agencies for a simplified model, perhaps incorporating 3 to 5 composite storage reservoirs, capable of regulating flows and quantifying trade-offs between fish and hydropower production (Maher, 1984). To illustrate the result of proposed changes in operating policies as a result of the Water Budget, such a model would need to include one composite reservoir west of the Cascades. The fisheries agencies would benefit from the simulation of turbine-related mortality as well as flow-related mortality at each project. The CRFISH model (Johnson, 1981) could be adapted for inclusion into the model; the fact that the system modeled is not internal to the program allows the user to incorporate the desired degree of complexity into the model.

The model should be designed for use with synthetic inflows at each project. The representation of streamflows as realizations of a stochastic process rather than a deterministic sequence of events would be a great improvement on the approach which the hydro regulators currently use. The use of synthetic inflows is considered one aspect in which CRISP creates a more realistic picture than the complex HR models, which use the same record of flows for every regulation. This approach enables the researcher to examine the sensitivity of the system to critical parameters over a wide range of flow conditions.

The methods used in CRISP to develop energy content curves and variable energy content curves could be applied to develop such curves for multiple composite reservoirs. The model could be calibrated using results from a selected seasonal HR model. Given that all data used for calibration would be monthly, the time step used in the model should be monthly.

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APPENDIX

The Interview Process

In an effort to develop criteria which could be used to evaluate the Columbia River fish and hydropower production models, a series of interviews were conducted with representatives of federal agencies and private concerns involved in management of the river. Formal interviews were conducted with representatives of the North Pacific Division of the Corps of Engineers, the Bonneville Power Administration, the Northwest Power Pool, and the Intercompany Pool. In addition, personal correspondence with representatives of the National Marine Fisheries Service and the Washington State Department of Fisheries helped to assess the appropriateness of existing models for conflict resolution. References to their remarks are found within the main body of the report (see references to Maher and Packard in Chapters 7 and 5, respectively). The following is a list of the interviews conducted for this study, after which is given a brief account of the main points of each interview.

List of Interviews

Gary Flightner, Chief, Power Section, North Pacific Division, U.S. Army Corps of Engineers, Portland, Oregon (January 24, 1984).

Michael Hansen, Coordinating Group, Northwest Power Pool, Portland, Oregon (January 25, 1984).

John Hyde, Power Resources Capabilities Section, Bonneville Power Administration, Portland, Oregon (January 25, 1984).

William McGinnis, Power Section, North Pacific Division, U.S. Army Corps of Engineers, Portland, Oregon (January 24, 1984).

Richard Mittelstadt, Power Section, North Pacific Division, U.S. Army Corps of Engineers (January 24, 1984).

Merrill Schultz, Director, Intercompany Pool, Spokane, Washington (March 21, 1984).

Gary Flightner, U.S. Army Corps of Engineers

According to Mr. Flightner, there are some aspects of the Corps' seasonal hydro regulator model (HYSSR) which are too detailed; he attributes this to the "tendency to refine things that you can refine." Flightner believes that HYSSR comes out with about the same regulation as BPA's HYDRO model, even though HYSSR does not have a critical period optimizer such as BPA's CPOPT. HYSSR was chosen by the Instream Flow Work Group in 1982 over BPA's and NWPP's seasonal models to determine the impact of various fish flow schemes on FELCC because, at that time, it was the only one of the three which could use flow requirements as the regulation objective function.

William McGinnis, U.S. Army Corps of Engineers

Mr. McGinnis, who works daily with the Corps' HYSSR model, believes that this model is superior to the other seasonal regulation models in identifying conflicts between water uses. The model can be used to determine the impact on FELCC of various fish flow schemes (meeting target streamflows) by proportionally drafting between power rule curves at all upstream projects. The model has had no major revisions since November, 1980, when the fish flow mode of operation was included. McGinnis plans to develop fish flow curves, which will ensure that major headwater reservoirs (Canadian) need not be drafted for fish flow requirements.

The major assumption behind the model is that monthly flows adequately determine the hydro generation in that period. Another assumption is that there is no time delay between water released from upstream projects and arrival at downstream projects; this is valid for a monthly routing model using monthly flows. Such an assumption is not valid for hourly models. The major limitations of the model are the "bulk of data" required as input and the fact that the model is "hard to run and tough to learn how to run." Even with this level of processing complexity, McGinnis believes HYSSR is easier to use than BPA's HYDRO, and the output is easier to read. McGinnis agrees with Flightner that "there is overkill in a lot of places in the program." Simplifications to a seasonal regulation model could include using a composite Canadian project and modeling H/K (which gives the number of megawatts generated by an outflow of one kcfs at each particular project) as a function of head only (assuming a constant efficiency). HYSSR models H/K as a function of head and efficiency, which is itself a function of head.

John Hyde, Bonneville Power Administration

BPA's seasonal regulation model, HYDRO, and its critical period optimizer, CPOPT, are used by the agency as the basis for estimating future firm and secondary hydropower resources. According to Hyde, the major assumptions behind the model are: a) historical monthly streamflow records are an accurate and representative sample with which to predict future conditions, b) forecasted loads are accurate, c) plant characteristics submitted by project owners are accurate, and d) monthly time periods accurately simulate actual operations. Hyde believes that the first assumption is probably the one most vulnerable to error; measurements of Q at dams frequently have errors on the order of 10 percent; flow measurements at some sites may have errors as large as 20 percent; but the overall error in historical records is probably less than 5 percent. The 40-year streamflow record (1928 to 1968) which is used as a sample of possible streamflow conditions has been extensively examined because of objections that it leads to conservative operating policies. BPA feels that the critical period method of determining firm load carrying capability from these streamflow records gives a reasonable estimate of system reliability. They plan to begin using the 1980 update of streamflow records for 50 years of historical streamflows (1928 to 1978) in the near future. In addition, it is in the interest of the individual project owners to report larger heads and efficiencies than actually occur because this increases their rights to Firm Load Carrying Capability under the Coordination Agreement. However, this small percentage of error is probably minor when compared to the errors introduced by the other assumptions. Even if all of the above values were completely accurate, monthly simulation can only approximate the effects of daily and hourly changes in loads, flows, and operating constraints. Hyde believes that the overall impact of these errors on estimating system generation is minor when comparing the difference between two studies that change only one variable, such as loads, constraints, or plant characteristics.

Hyde believes that HYDRO is the most complex of the seasonal hydro regulation models. The model contains features which are absent from HYSSR and HYDREG, including CPOPT and switches such as the ones for overriding rule curves. While BPA is aware that use of the optimizer may only increase FELCC by 50 MW for a 12,000 MW system, Hyde feels that the optimizer is an important and necessary feature of the model, because contracts are made on the exact MW output from the model even though the inherent errors in the model are over 50 MW. BPA is aware that "the Corps doesn't think much of our optimizer," an attitude which was expressed in interviews with Corps personnel. Because power generation is not the Corps' only responsibility, they feel no obligation to optimize it at the expense of other uses.

A great deal of familiarity with the model is required before a user is "fully competent;" it typically requires 3 to 6 months before a user is able to run the model with some supervision, and a full 2 years before a user would be able to conduct a study independently. Because of the difficulty in running the model, Hyde is highly supportive of the recommendation of a simplified, user-friendly, seasonal hydro model. In his opinion, such a model would be tremendously useful to fisheries agencies unaquainted with the use of HYDRO. Hyde suggested 10 to 15 major projects that would need to be included in a useful model, specifically listing the Columbia River hydro system projects: The Dalles, John Day, McNary, Dworshak, Brownlee, combined lower Columbia and combined lower Snake projects, Chelan, Grand Coulee, Mica, Duncan, Libby, Kootenay Lake, Arrow Lakes, Hungry Horse, Kerr, and Albeni Falls. He feels that too many small projects which are insignificant in terms of their power generation are included in HYDRO; such projects are included for legal contract purposes only. Many run-of-river projects, such as those on the Lower Columbia and Snake, could be locally combined where inflows were correlated. In addition, two western reservoirs, Ross and Mossyrock, should be included, to provide for storage of water during the fish flow period when eastern reservoirs must be drafted. The model should simulate regulation for one or two years at a time, so that it can be highly interactive. The model could be calibrated using HYDRO.

Michael Hansen, Northwest Power Pool

The Northwest Power Pool (NWPP) is the custodian of the PNCA Seasonal Hydro Regulation Program (HYDREG). The model is used to determine the Coordinated System's FELCC, and to develop rule curves for reservoir operation. According to Hansen, the major assumptions behind the model are: plant characteristics submitted by the individual project operators are accurate; and the flows, loads, and regulation are modeled on a monthly basis. Hansen indicated that there are no plans for major revision of the model in the near future.

Hansen feels that there are aspects of the model that are too refined for the overall picture; the model includes many small projects which produce insignificant amounts of energy when compared to the total system generation and which, because they are run-of-river projects, do not affect the regulation of the system. However, they must be included to satisfy the requirements of the Coordination Agreement. For example, a 3 MW project may not be important to the region as a whole, but it certainly would be to a small utility district.

According to Hansen, the HYDREG model is less complex than BPA's seasonal model, HYDRO. The program itself is easier to use. An estimated 1 1/2 years are required before a typical user is considered fully competent in using the model. In Hansen's opinion BPA's HYDRO might be a more portable model than HYDREG; it would be easier to apply to other systems outside the region than HYDREG would. HYDRO handles each reservoir as a general case, whereas HYDREG was written more specifically for this system. However, HYDREG is maintained on an IBM computer, a more universal machine than the CDC, on which HYDRO is currently maintained.

Hansen had several suggestions for simplifications which could be made to the seasonal hydro models so that they could be combined with a simple fish production model. Many run-of-river projects could be combined into component project(s). The three Canadian projects could be merged into one or two, such as Mica and Arrow together. To take into account overgeneration occurring in May as a result of the Water Budget release, a reservoir in western Washington could be modeled, storing water which would otherwise be released to produce firm energy. Energy demand ordinarily supplied by the western reservoirs would be supplied by the reservoirs participating in the draft for fish flows. This is the operating procedure which has been suggested to compensate for overgeneration in eastern projects. Such a procedure would decrease the impact of the Water Budget on FELCC. However, because all of the data for these projects are published separately (rule curves, etc.), the simplifications to the model might very well be offset by the additional work required to adapt the data to a component reservoir.

Richard Mittelstadt, Corps of Engineers

The Corps of Engineers currently maintains and operates two hourly hydro simulation models. The PONDAGE program takes the monthly regulated flows determined by the seasonal hydro regulation program (HYSSR) as input, and simulates the hourly operation of the system for a week. For every project, the program calculates the hourly release, power generation, head, and water surface elevations, along with rates of change and peaking performance. The second model, HYSSIS, is useful for exact simulation of the system operation. The user must specify the hourly load to be met by each project. This program is much more detailed than the PONDAGE program, is cumbersome to use, and is therefore not used regularly by the Corps.

The major assumption behind the PONDAGE program is that hydro maintenance will have no effect on system generation; this is an idealized approach which overestimates true peaking capacity of the system. In addition, navigational and other special operations are not presently included in the model, but there are plans to include these stochastic elements eventually.

According to Mittelstadt, the program is relatively hard to use. Someone very familiar with the model may require two or three runs of the model before they achieve a "balanced run;" someone less familiar may require up to 10 runs or may simply be unable to achieve a balanced run. The model is useful in identifying conflicts between hydro and environmental concerns, mainly the impacts of peaking on water surface elevations and rates of change. The Corps' hourly production cost model, POWERSYM, using a single composite reservoir, achieves the same basic dispatch of hydro as the PONDAGE program does, verifying the usefulness and appropriateness of the one-reservoir approach in instances where the allocation of load among plants is not of interest.

Merrill Schultz, Intercompany Pool

Merrill Schultz, Director of the Intercompany Pool, is author of several hydropower simulation and system reliability models currently in use in the Pacific Northwest. The PNCA Seasonal Regulation Program, HYDREG, was developed by Schultz at the Northwest Power Pool.

According to Schultz, a major assumption/limitation of the model is that it is a deterministic simulator of a set of stochastic processes, and is therefore a crude representation of reality. Historic flows are used as representative of all possible hydro conditions. The approach is admittedly a poor probabilistic representation of the system, but it is widely accepted because it follows standard procedures which energy planners understand. A more realistic approach would be to build sets of synthetic flows for the 150 projects in the system and develop statistics on the energy produced. However, since the flows at these points are all correlated, implementation of this approach would be next to impossible.

Schultz believes that the physical model of the system is a better representation of reality than the management model. The "biggest failing of the monstrous [monthly hydropower] simulators" is that they do not take into account the utilities' attempts to get the most value out of their hydro resources. This failure is related to the fact that the models do not conduct economic analysis and include contributions from thermal sources as a constant factor (an unrealistic assumption).

Comparing HYDREG to other monthly hydro simulation models, Schultz claims that the physical models incorporated into HYDREG, HYDRO, and HYSSR are essentially the same. The major difference between HYDREG and HYDRO is HYDREG's lack of a critical period optimizer. The NWPP developed and attempted to run their own version of the optimizer, with the incentive being automation of rule curve development, not FELCC optimization, but they were using PP&L's computer at the time. The optimizer made execution of the program too expensive, and its use was therefore discontinued. HYDRO and HYDREG do essentially the same thing once the rule curves have been established. The major difference between HYDREG and the Corps' model, HYSSR, is that HYSSR uses polynomials to represent plant characteristics, while HYDREG (and HYDRO) use straight line sections of curves. Despite these differences, given similar input, each model produces similar results.

Schultz characterizes HYDREG as "extremely complex," and "unnecesarily complex for many purposes." The model's complexity is primarily caused by the incredible detail of the physical model. The justification for the complexity of the physical model is that "each individual utility is concerned that its own resources be represented accurately." As a result, the model includes projects which are "trivial" contributions to the total system energy production. For example, Willamette Falls, with a total capacity of 13 MW, is typical of small projects for which pages of coding are necessary. The processing complexity of the program is a major factor limiting the potential use of the model. The bulk of the data sets required and the manipulation of these data by numerous ancillary programs, the "overkill" in the volume of output, and problems interpreting large volumes of output all contribute to the model's intimidating complexity.

The unrealistic treatment of thermal resources in the monthly hydropower simulation models was Schultz's main impetus for developing ERPM, the Energy Reserve Planning Model. The monthly simulators assume that hydro resources are infinitely shapeable, by assuming that there is a constant contribution of thermal power, thereby ignoring constraints on the system. ERPM is a "simple, manipulable model which provides a more comprehensive treatment" of what actually goes on in the real system, by integrating thermal and hydro resources and balancing the detail with which these types of resources are modeled. Rather than combining an incredibly detailed (yet unrealistic) representation of hydro resources with a constant thermal resource, ERPM combines a composite, one-reservoir model of the hydro system with a thermal resource subject to uncertainties in plant arrival dates and unit availability (forced outages and scheduled maintenance). Schultz sees ERPM as a "crude" model, but is convinced that it is not disproportionately cruder than the models combining detailed hydro treatment with negligible treatment of thermal resources. ERPM has not been widely accepted throughout the region. Schultz believes one of the reasons it did not gain acceptance is because it uses a new approach, and energy planners like to use what they are already familiar and comfortable with.

Schultz wrote ERPM as a pedagogical model. He felt that many veteran hydro system managers did not really understand the nature of the system. That the real dividing line in terms of operations policy is the energy content curve (ECC), and that all other rule curves below ECC function only to allocate draft between reservoirs, are facts which he used ERPM to demonstrate, via the one-reservoir model.

The use of a one-reservoir model to represent the hydro system dates back to the Stanford Water Utilization Research Project. The researchers assumed infinite generation capacity at all projects and no regulation to determine the natural streamflow capability (in MW-months) of the hydro system. This single value of system output was then compared with outflow at The Dalles, and it was found that the two values were almost perfectly correlated. On this basis, a one-reservoir model of the system was proposed and constructed. According to Schultz, the one-reservoir model provides a sufficiently good picture of reality except during seasons of refill.

The Systems Analysis Model (SAM) of the Pacific Northwest Utilities Conference Committee (PNUCC) is an offspring of ERPM. Proposed by the Intercompany Pool (ICP) and developed for the PNUCC by the ICP and BPA, the model has been adopted by the Northwest Power Planning Council as the basis for their regional planning efforts. The model develops operating policies based on cost effectiveness, a criteria mandated by the Regional Power Act of 1980. SAM is widely accepted throughout the industry.

SAM incorporates physical, management, and financial models of the hydro and thermal resources of the region. The model determines the most cost effective combination of hydro and thermal power generation, and goes to a physical hydro model to determine a regulation to achieve that generation. Depending on the degree of temporal resolution desired, the program uses one of a variety of physical models. If seasonal simulation is required, ERPM's physical model is used, for monthly simulation HYDREG is used, and for hourly simulation, the PONDAGE model is used. Any combination of time intervals may be specified. Usually, the hourly simulation is only run as a check on whether project operating constraints are being violated.

SAM represents a great breakthrough in the modeling of the management process. It is the first regional model to operate the system on an economic criterion. The model is not a step forward in hydro modeling, however, as existing models were simply incorporated into the model. Schultz finds each of the physical hydro models perfectly acceptable. He would like to see a synthetic flow generator incorporated into the seasonal flow model, but it could only be used if the entire analysis was seasonal.

Schultz characterizes SAM as "hugely complex," and "probably the user-unfriendliest model to ever be built." The model is very large, since it incorporates three physical models (two very large, one relatively small), a management model, and a financial model. According to Schultz, the management model is at least as complex as the physical model, and the financial portion of the model takes at least as much time as the physical model to run on a computer. The financial analysis is the most questionable part of SAM. Debate still exists between its developers on how to treat results at the end of the financial analysis period.