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Report documenting the application of the HEC-Prescriptive Reservoir Model for evaluation of three operation scenarios of the Columbia River system. The evaluation was performed to optimize the operation of: (1) existing policy with existing Canadian Treaty; (2) hydropower objectives were omitted; and (3) additional Canadian water is provided by Mica Reservoir. Conclusions include: HEC-PRM analysis performed successfully for the Columbia River System; three alternatives specified by CENPD were evaluated and compared; penalty functions were successfully used; using more storage at Mica does not significantly improve system performance; omitting the hydropower objective enhances system fish protection, navigation and recreation at the expense of system hydropower.

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Executive Summary

In 1990, the U.S. Bureau of Reclamation, Bonneville Power Administration, and the Corps of Engineers initiated the Columbia River System Operation Review (SOR). The SOR goals are: (1) to identify system operation issues; (2) to identify alternative system operation rules that would respond to these issues; (3) to evaluate trade-offs in satisfying conflicting needs for water and storage users if the rules are followed; and (4) to make decisions regarding changes in the operation policy.

For Corps use parallel to the SOR study, the Hydrologic Engineering Center (HEC) was requested to develop a system analysis model and apply it for preliminary evaluation of the following Phase II operation scenarios:

Alternative 1, in which operation is optimized for existing policy, with the Existing Canadian Treaty;

Alternative 2, in which hydropower objectives are omitted; and

Alternative 3, in which additional storage is provided at Mica Reservoir.

The mathematical tool used for the evaluation was HEC-PRM, a prescriptive reservoir operation model developed by HEC. HEC-PRM represents reservoir operation as a network-flow programming problem with flow, release, and storage decision variables. Goals of operation are defined formally with penalties valuing different aspects of system performance with upper and lower bounds on storage and releases. HEC-PRM prescribes storages and releases that meet the physical constraints and minimize total system penalty. For reference, optimal performance for each alternative was compared with performance following existing rules, as simulated with HYSSR, a model developed over 35 years by NPD staff for use in coordinated operation of the Columbia River System.

The modeling results support the following conclusions:

- HEC-PRM system analysis has been successfully modified and improved for application to the Columbia River System.

- The analysis provides results that enable comparison of three alternatives specified by NPD.

- Penalty functions must be constructed with care to reflect system physical characteristics and practical aspects of desired flow regimes in the functions.

- Using more storage at Mica does not significantly improve system performance.

- Omitting the hydropower objective enhances system fish protection, navigation, and recreation at the expense of system power.

Preface

The investigation reported herein is Phase II of a two-phased study involving development and application of a system analysis model to the Columbia River reservoir system. HEC-PRM applies network-flow programming, a special case of linear programming, to reservoir system operation analysis. The model was developed at the request of and with funding from the North Pacific Division (NPD) Corps of Engineers, USACE. NPD staff provided basic data and general guidance for the study.

This study was conducted by the Hydrologic Engineering Center (HEC), Davis, California. Bob Carl, senior engineer, developed the HEC-PRM computer software, contributed to the overall analysis and generated the post-processed results. Richard Hayes, hydraulic engineer, and Marilyn Hurst, computer programmer, performed data preparation, model application, and synthesis of the results. Loshan Law typed and assembled the report. Mike Burnham, Chief, Planning Analysis Division, and Vern Bonner, Chief, Training Division, provided study direction and management. Darryl Davis, Director, provided general supervision and guidance for the project.

Dave Moser of the Institute for Water Resources (IWR), Corps of Engineers, supervised development of penalty functions for the analysis and provided guidance in their interpretation and application. Documentation of penalty functions is presented in an IWR companion draft report, "Economic Value Functions for Columbia River System Analysis Model: Phase II", August 1993. David Ford, consulting engineer, Sacramento, California, advised HEC in model development and application and prepared drafts of this report. Quentin Martin, Lower Colorado River Authority, Austin, Texas, made significant contributions to model development and application while at HEC on an Intergovernmental Personnel Act assignment. He played a key role in implementing and testing the hydropower algorithm. Paul Jensen, University of Texas at Austin, developed the improved network solver incorporated in HEC-PRM. Jay Lund, University of California, Davis, offered advice during model application, helped interpret the results, and contributed to this report.

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Chapter 1

Introduction

1.1 Purpose

This report documents the development of a system analysis model (HEC-PRM) and its application to the analysis of the Columbia River reservoir-system operation. It describes the system model and presents findings of model application for a limited set of evaluation conditions. The findings are interim in the sense they are based on the best available system penalty functions as of January 1993. The findings could change as the penalty functions become more complete and defined throughout the system. However, the trends and results obtained from the evaluations are deemed reasonable and meaningful for preliminary comparison of the operation alternatives examined by application of the HEC-PRM program.

1.2 Background

The Columbia River basin covers 259,000 sq. mi. in Washington, Montana, Oregon, Idaho, Wyoming, Nevada, Utah, USA; and in British Columbia, Canada, as shown on Figure 1.1. The basin includes more than 250 reservoirs and 100 hydroelectric projects on the Columbia, Snake, Kootenai, Clearwater, and Pend Oreille Rivers and their tributaries. More than 120 of these projects comprise the coordinated Columbia River Reservoir System. The U.S. Army Corps of Engineers (Corps) and the U.S. Bureau of Reclamation (Reclamation) operate this coordinated system for power generation, flood control, anadromous-fish protection, navigation, and irrigation. Other river uses include water supply, recreation and fish and wildlife. The Bonneville Power Administration (Bonneville) sells the power produced.

Problems faced recently by Corps, Reclamation, and Bonneville in operating the coordinated system are summarized by these agencies in *The Columbia River: a system under stress* (BPA, COE, USBR, 1990). There they write:

> *Growth in our region, along with changing priorities, are putting our river system increasingly under stress. There simply is not enough water flowing in the system to meet all the demands. Trade-offs must be considered ... in recent years, demands by the various users of the river have increased dramatically, resulting in increasing conflicts among uses.*

Accordingly, in 1990, the three federal agencies (Corps, Reclamation, and Bonneville) began a system operation review (SOR). In February 1991, NPD asked the Hydrologic Engineering Center (HEC) to develop a system analysis model for Corps use parallel with the SOR. After considering several options, the HEC prescriptive reservoir model, HEC-PRM, was selected

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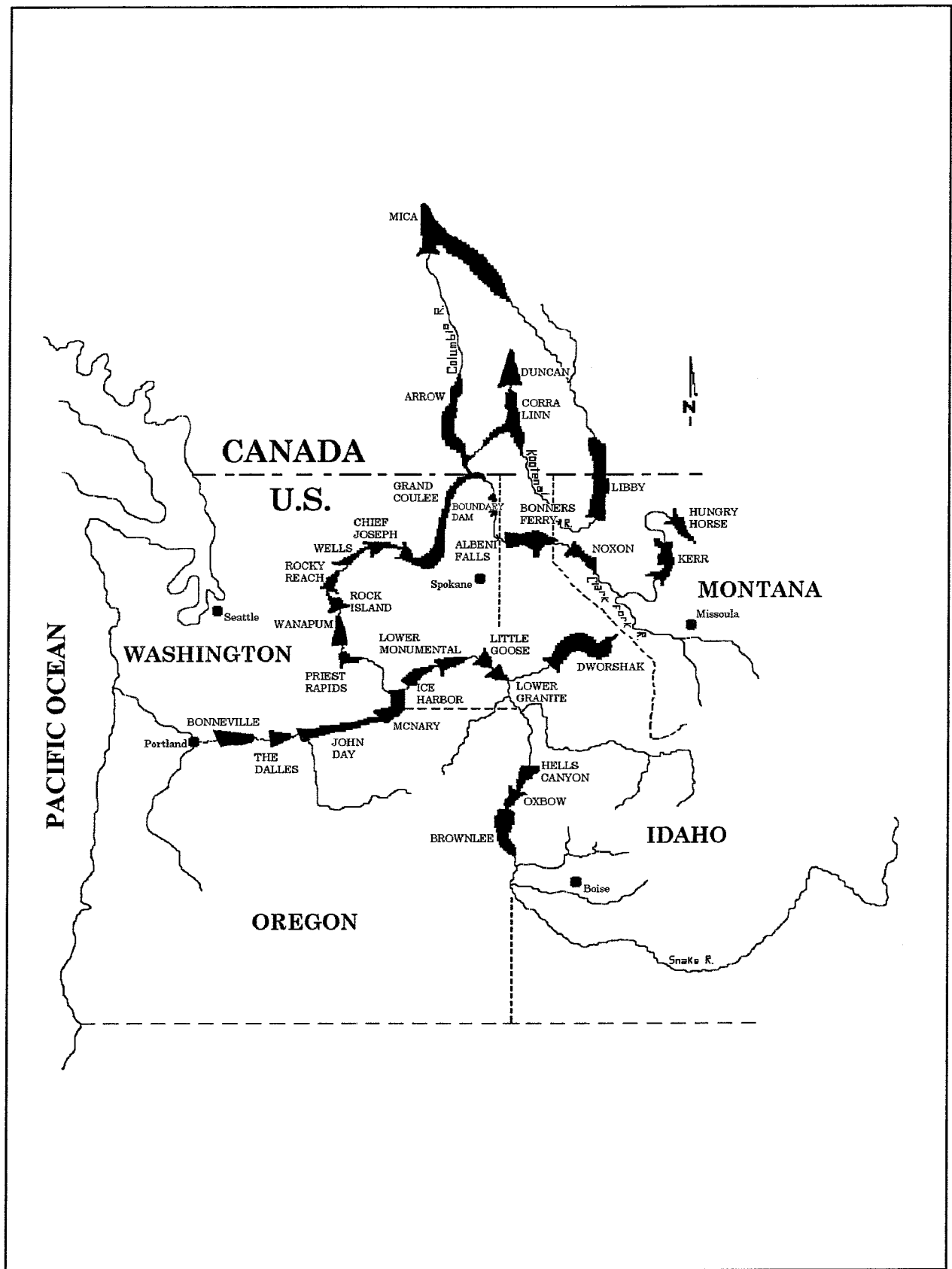
FIGURE 1.1 Columbia River System

for the analysis. HEC-PRM is designed to enhance evaluation of all operation goals and assist in performing trade-offs analysis for multipurpose multireservoir systems.

1.3 Report Overview

Chapter 2 provides background on HEC-PRM and how the Columbia River System was modeled in Phase I of the study. The chapter also summarizes the HEC-PRM validation and Phase I application.

Chapter 3 describes research and development for the Phase II model development and application for the study. It documents improvements made to HEC-PRM and describes how the Columbia River System was modeled in Phase II.

Chapter 4 overviews existing system operation and describes three alternative Columbia River System operation scenarios being considered for the SOR and how each was modeled and compared for system performance. These alternatives were selected to provide a demonstration of model use and also to provide insight for a selected set of very different operation goals.

Chapter 5 summarizes the interim findings of this study and makes recommendations regarding additional analysis and use of HEC-PRM for the Columbia River System.

Appendices are organized as follows: Appendix A is a detailed description of HEC-PRM; Appendix B describes how HEC-PRM determines prescribed system operation for hydropower; Appendix C is a list of references; Appendix D shows the HEC-PRM program input for the alternatives evaluated; Appendix E presents penalty functions at selected locations; Appendix F displays times-series results from the alternatives evaluated for selected locations; Appendix G shows time-series plots of energy production.

A companion report by IWR (USACE, 1993) presents detailed information on the development of penalty functions used in the Columbia River network flow model.

Chapter 2

Columbia River System Model

2.1 Role of Modeling in the SOR

According to the System Operation Review (SOR) plan of study, (USACE, 1990a), the investigation will:

- Identify and consider outstanding and unresolved issues regarding operation and use of the existing system of federal multiple-purpose water resource projects;

- Identify and evaluate alternative operation plans in response to public identification of water resource issues;

- Consider implementation of operational changes in response to issues within the existing authorities of the three responsible federal agencies;

- Consider operation plans and criteria to improve the balance among authorized uses;

- Evaluate and report on potential operational changes in response to issues that exceed existing authorities of the three agencies;

- Coordinate power generation operations of federal and non-federal projects to produce maximum power for the system as a whole in a manner consistent with non-power uses; and

- Prepare an environmental impact statement that will enable the three federal agencies to decide future actions on coordinated operation agreements.

To accomplish these goals, an array of operation schemes for various project purposes must be identified. These schemes then must be compared in terms of physical, social, economic, and environmental effects. Such a comparison is reasonably accomplished with a computer model of reservoir system operation. Numerical modeling approaches appropriate for this analysis include:

Enumeration-with-simulation. With this approach, an analyst enumerates trial policies, simulates system operation with each, and evaluates each using the simulation results. The best of the alternatives that are nominated, simulated, and evaluated is declared the optimal policy.

Mathematical programming. This approach employs a calculus-based operations-research tool to iteratively suggest alternative policies and to evaluate the feasibility and efficiency of each policy with an embedded simulation model. The operations-

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research tool leads systematically from one alternative to another until all alternatives are evaluated or eliminated because they are infeasible or inferior.

The HYSSR computer simulation program, a model developed by NPD staff and used over a period of 35 years for use in coordinated operation of the Columbia River System (USACE, 1982b), is used in the SOR study to enumerate and evaluate alternatives. With HYSSR, the system's physical response is analyzed for the following alternatives: (1) operation following current regulation rules; (2) operation without PL 96-501 requirements; (3) operation emphasizing fish and wildlife; (4) operation emphasizing river and reservoir recreation; (5) operation with alternative power systems; (6) operation with different navigation objectives; (7) operation with changes in irrigation; and (8) operation with modified flood-control objectives. According to the SOR plan of study (USACE, 1990a), "Other models will be used ... to assist in accomplishing social, economic, and environmental analysis of the physical responses ... to various scenarios and alternatives to be analyzed."

The mathematical-programming tool, HEC-PRM developed in preliminary form for the Missouri River System (USACE, 1992), was selected for further development and application. HEC-PRM is a prescriptive reservoir system operation model. It prescribes reservoir-system operation to achieve user-defined goals. To do so, it represents reservoir operation as a network-flow programming problem with flow, release, and storage decision variables. Goals of operation are defined formally with value functions represented as penalties related to storage and release. The penalty functions are typically economically based, but can be based on other performance criteria. Software to implement HEC-PRM is generalized. It incorporates a network generator, a network solver, and the HEC Data Storage System (HEC-DSS) (USACE, 1990d). The program user's manual (USACE, 1991b) and Appendix A of this report describe HEC-PRM in more detail.

The system analysis was divided into two phases. Phase I developed a preliminary model and tested the applicability of the approach. Phase II developed user interfaces, output reports, and documentation and accomplished selected detailed analyses.

2.2 Phase I Columbia River Reservoir System Model

Phase I study details are presented in the Phase I report (USACE, 1991a). In Phase I, the Columbia River System is represented with a network of 21 nodes and 20 links for each period of analysis. Reservoir inflows or incremental local flows are added to the system at each of the 21 nodes. Thirty storage and pondage projects are represented by 18 nodes. Three additional nodes (Mica, Arrow, and Duncan) are included in Phase II to represent additional reservoirs at which operation goals are specified. Functions that define penalties for too much or too little flow, release, or storage throughout the system were developed by the staff of NPD and its districts, assisted by USACE Institute for Water Resources (IWR).

2.3 Validation and Phase I Applications

Phase I validated HEC-PRM by comparing prescribed operation for September 1969 to July 1975 with operation for the same period following current rules. HEC also demonstrated use of HEC-PRM to prescribe operation for the system critical period, July 1928 to February 1932.

2.3.1 Validation. The initial Phase I step conducted a subjective test to validate performance of HEC-PRM. Although validation in the strictest sense is not possible, the test was to identify obvious shortcomings of HEC-PRM, inexplicable results, or weakness that would render its use unacceptable for further analysis.

The test was based on the following premises:

Current penalty functions reflect benefits foregone associated with nodes and links defined in the model. In a given user's penalty function, the flow, storage, or reservoir release with minimum penalty represents the best operation for that user.

Benefits foregone correlate with historical operation, which follows current rules. For example, lake recreational boat docks are built to function at lake surface elevations within the range normally experienced.

If these premises are true, it follows that the current penalty functions are an approximate mathematical representation of the current rules. Thus minimum-penalty operation prescribed by HEC-PRM should reasonably match operation that follows current rules, if it is modeling system performance properly.

HEC-PRM prescribed monthly storages, releases, and flows for September 1969 to July 1975 were compared to monthly storages, releases, and flows reported by HYSSR for current operation rules. This period includes two flood events and a low-flow period. For the Phase I HEC-PRM analysis, reservoir evaporation losses were assumed independent of system operation, hydroelectric-power penalties were assumed a function of release only, and Mica and Arrow reservoir releases were specified. HYSSR results were used for validation purposes because they provided constant level of development, the results were readily available, and NPD staff were familiar with the operation of the program. A perfect match of results was not expected. Indeed, the results were not expected to be identical as the models employ different simplifications of the prototype and operate for different goals.

The results of the Phase I HEC-PRM and HYSSR applications were found to compare well. The comparison of total system storage determined by HYSSR and HEC-PRM shown in Figure 3 of the Phase I report supports this conclusion.

The finding of the Phase I validation study: HEC-PRM prescribes reasonable operation for the Columbia River System.

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2.3.2 Critical-period Analysis. System operation for the critical period from July 1928 to February 1932 with (1) the best-available penalty functions and (2) inviolable flow constraints for April-September to improve fish migration at Priest Rapids, The Dalles, and Lower Granite were analyzed to demonstrate further the applicability of HEC-PRM as a viable tool for the SOR. This analysis concluded that HEC-PRM could model adequately system operation for the wide variety of goals and objectives to be considered in the SOR.

Chapter 3

Research and Development for Columbia River System Analysis

3.1 Research and Development

The following tasks were performed as part of improvement to the Phase I HEC-PRM application (USACE, 1990e):

System model expansion. The goals of this task are (1) to expand the Columbia River System model to include additional upstream and tributary reservoirs, intervening and downstream reaches, and system operation purposes as needed; (2) to analyze the full flow record; (3) to develop methods to account for future diversions and techniques to permit analysis of selected time periods from the historical record; and (4) to document construction of the model and data preparation.

Penalty function refinement. The penalty functions used in the Phase I analyses were based on the then best available data. The goal of this task is to expand these functions to include all project purposes, stream reaches, and reservoirs, and current data.

Software improvement. The goal of this task is to modify the HEC-PRM software, especially the network generator, to meet the special modeling needs of the Columbia River System, particularity the representation of hydro-electric power generation.

In addition to the technical tasks, the following technology-transfer activities were proposed: (1) expand and improve the draft HEC-PRM user's manual, and (2) formulate and present a model-application workshop for NPD staff.

3.2 System Model Expansion

3.2.1 Expand System Model. Figure 3.1 shows the Columbia River System as defined for Phase II analysis with HEC-PRM. For a single period, the network consists of 22 nodes and 21 links. The nodes represent thirty storage or pondage projects and three additional system control points, as shown on Table 3.1. Pertinent characteristics of the projects and control points are summarized on Table 3.2. Reservoir inflows or incremental local flows are added to the system at each node. The links that interconnect the nodes and their operational purposes are described on Table 3.3. The operational purposes by link are also shown on Figure 3.1.
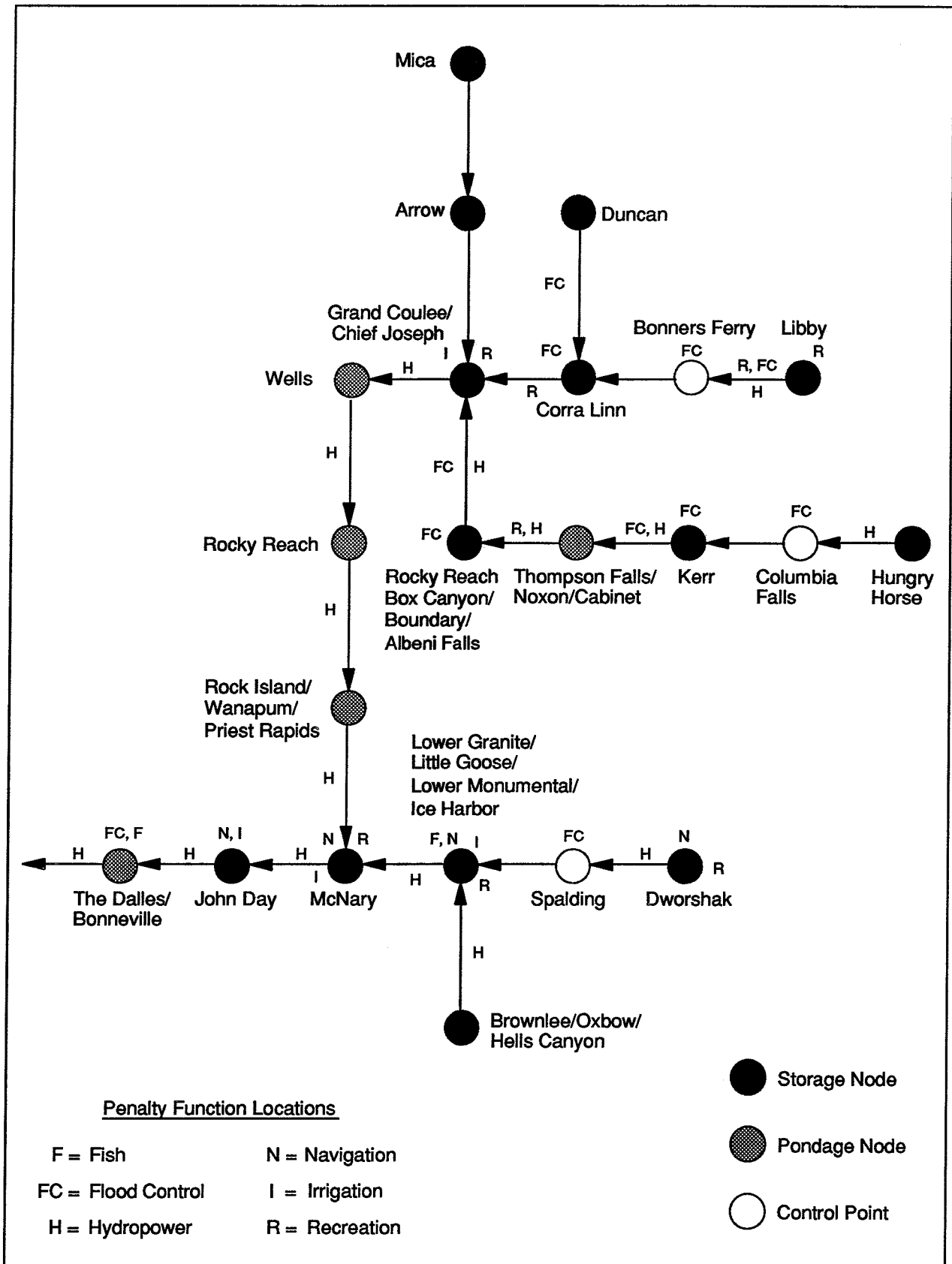
FIGURE 3.1 Single-period Network Model of Columbia River System

TABLE 3.1
Columbia River System Phase II Network Nodes

Node[1]	Representation of Facility
Libby	Storage
Bonners Ferry	Control Point
Corra Linn[2]	Storage
Duncan[2]	Storage
Hungry Horse	Storage
Columbia Falls	Control Point
Kerr	Storage
Thompson	Pondage
Albeni Falls	Storage
Dworshak	Storage
Spalding	Control Point
Brownlee	Storage
Granite	Storage
Mica[2]	Storage
Arrow (Keenleyside)[2]	Storage
Coulee	Storage
Wells	Pondage
Rocky Reach	Pondage
Rock Island	Pondage
McNary	Storage
John Day	Storage
Dalles	Pondage

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[1] Refer to Figure 3.1 for relative location of nodes. In this table, Thompson = Thompson Falls+Noxon+Cabinet; Albeni Falls = Albeni Falls+Box Canyon+Boundary; Brownlee = Brownlee+Oxbow+Hells Canyon; Granite = Lower Granite+Little Goose+Lower Monumental+Ice Harbor; Coulee = Grand Coulee+Chief Joseph; Rock Island = Rock Island+Wanapum+Priest Rapids; Dalles = The Dalles+Bonneville

[2] Canadian Project

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TABLE 3.2
Columbia River System HEC-PRM Model Storage and Release Limits

| Reservoir | Storage Limits, 1000 Acre-Feet | | Release Limits - CFS | |
	Minimum	Maximum[1]	Minimum[2]	Maximum[3]
Libby	889.9	5,869.4	3,000	--
Corra Linn	144.0	9,999.0	--	55,940
Duncan	30.0	1,398.6	100	--
Hungry Horse	486.0	3,647.1	400	--
Kerr	572.3	9,999.0	1,500	54,930
Albeni Falls	446.4	9,999.0	--	129,800
Dworshak	1,452.2	3,468.0	1,000	--
Brownlee	431.7	1,426.7	5,000	--
Lower Granite	144.0	1,825.0	--	--
Mica			--	--
Alternatives 1 & 2	13,075.0	20,075.0		
Alternative 3	8,000.0	20,075.0		
Arrow	227.0	7,327.0	5,000	--
Grand Coulee	3,879.0	9,107.0	--	--
McNary	1,170.0	1,350.0	--	--
John Day	1,989.0	2,523.0	--	--

[1] Storage values of 9,999.0 are arbitrarily assigned due to the physical characteristics of the reservoir outflow conditions. (See Section 3.2.4)

[2] Minimum release limits were specified at reservoirs without penalty functions to prevent zero releases.

[3] Maximum release limits coupled with arbitrarily high storage limits at Corra Linn, Kerr, and Albeni Falls were assigned due to the physical characteristics of these projects. (See Section 3.2.4)

TABLE 3.3
Columbia River System Phase II Network Links and Operational Purposes

Original Node[1] (1)	Terminal Node[1] (2)	Link Type[2] (3)	Operation purposes modeled[3]					
			FC (4)	Hydro (5)	Nav (6)	Irr/WS (7)	Fish (8)	Rec (9)
Libby	Libby	S						✓
Libby	Bonners Ferry	H	✓	✓				✓
Bonners Ferry	Corra Linn	C	✓					
Duncan	Duncan	S						
Duncan	Corra Linn	R	✓					
Corra Linn	Corra Linn	S	✓					
Corra Linn	Coulee	R						
Hungry Horse	Hungry Horse	S						✓
Hungry Horse	Columbia Falls	H		✓				
Columbia Falls	Kerr	C	✓					
Kerr	Kerr	S	✓					
Kerr	Thompson	H	✓	✓				
Thompson	Thompson	S						
Thompson	Albeni	H		✓				
Albeni	Albeni	S	✓					✓
Albeni	Coulee	H	✓	✓				
Dworshak	Dworshak	S			✓			✓
Dworshak	Spalding	H		✓				
Spalding	Granite	C	✓					
Brownlee	Brownlee	S						
Brownlee	Granite	H		✓				
Granite	Granite	S			✓	✓		✓
Granite	McNary	H		✓			✓	
Mica	Mica	S						
Mica	Arrow	R						
Arrow	Arrow	S						
Arrow	Coulee	R						
Coulee	Coulee	S				✓		✓
Coulee	Wells	H		✓				
Wells	Wells	S						
Wells	Rocky Reach	H		✓				
Rocky Reach	Rocky Reach	S						
Rocky Reach	Rock Island	H		✓				
Rock Island	Rock Island	S						
Rock Island	McNary	H		✓				
McNary	McNary	S			✓	✓		✓
McNary	John Day	H		✓				
John Day	John Day	S			✓	✓		
John Day	Dalles	H		✓				
Dalles	Dalles	S						
Dalles	Sink	H	✓	✓			✓	

[1] Refer to Figure 3.1 for relative location of nodes and to Table 3.1 for meaning of abbreviated entries.

[2] R = simple reservoir-release link; S = storage (period to period) link; H = hydropower reservoir-release link; C = channel-flow link.

[3] FC = flood control; Hydro = hydroelectric-power generation; Nav = navigation; Irr/WS = irrigation and/or water supply; Fish = fish protection; Rec = recreation.

3.2.2 Flow Record. The fifty year period of 1928 - 1978 was adopted as a standard for the system operations studies. The adopted flow record, which was adjusted as described in Section 3.2.4, includes a mix of low and high flow periods believed to be representative and therefore enables a comparable basis for analysis of the alternatives for a static condition of the system. The use of an adopted record is necessary due to the uncertainty of future flow patterns and other system conditions.

Analysis of the full flow record for the Columbia system is limited by the great size of the problem. Each network arc must be stored in computer memory, and the number of arcs is a function of the number of system components multiplied by the number of periods in the record to be analyzed. The network for analysis of 50 years of operation of the full Columbia River System has approximately 150,000 arcs and 25,000 nodes.

Two solutions were employed to minimize memory requirements. The first used a FORTRAN compiler that provides access to extended PC memory. With extended memory access, system-memory limitations are overcome by increasing the available memory. The other solution is to use a network solver that incorporates an efficient data structure, reducing the number of arcs required to model the system. This solver is described in further detail by Jensen (1991b). With these two measures adopted, solution of the full network of 150,000 arcs and 25,000 nodes for 50 years of monthly operation requires about 13 MB of memory, well within the capability of PCs with extended memory.

3.2.3 Account for Diversions and Analyze Selected Time Periods. The HEC proposal prepared in 1990 anticipated that the network model of the Columbia system would be a handmade prototype. Consequently, any changes to system configuration would require re-formulation of the network. However, as the work progressed on this study and a parallel study of Missouri River system operation, more flexible software was developed. This software generates the network representation of the reservoir system from the user's description of system reservoirs, interconnecting channels, diversions, and hydropower facilities. Thus, to define an alternative system configuration, the analyst need only alter a few lines of input.

Similarly, it was anticipated initially that system inflows would be specified with fixed arc bounds in the handmade network. However, a network generator was developed that accesses flow data stored with HEC-DSS (USACE, 1990d). This greatly simplifies selection of the time period for analysis. The analyst must only specify a few input parameters to define the beginning and ending month and year of the time period. Data are retrieved automatically from HEC-DSS and network parameters are defined with these data.

3.2.4 Document Construction of Model and Data Preparation. Listings of the HEC-PRM input files used in the study are included in Appendix D of this report. These files and the associated HEC-DSS files for time-series flow data and the penalty functions are included on DOS-format diskettes that accompany this report.

The analysis period is July 1928 to June 1978. This includes the 1928 - 1932, 1943-1945, and 1977 critical periods. Phase I HEC-PRM flow data are based on data in *1980*

Level Modified Streamflow (Columbia River Water Management Group, Depletions Task Force, 1983).

In preparation of the modified streamflow, the Depletion Task Force accounted for the following:

(1) Reservoir storage effects are removed for all flows in the system. The result is termed adjusted flow;

(2) Evaporation losses are subtracted and gains added to adjusted flows for the period prior to construction of the current system reservoirs. Therefore, evaporative losses are treated by data adjustment, rather than by explicit accounting within HEC-PRM;

(3) Irrigation depletions for the 1980 level of development are subtracted from the adjusted flows. However, Bureau of Reclamation diversions from Grand Coulee for the Columbia Basin Project are not subtracted.

(4) Irrigation returns for the assumed 1980 level of development are added to the adjusted flows at the points of return. Grand Coulee Columbia Basin Project returns are added to the adjusted flows. The resulting flow data are termed modified flows.

To account for Reclamation's Columbia Basin Project withdrawals from Grande Coulee, negative inflows were included in the model to represent 1980 level irrigation depletions. Negative inflows were used in lieu of the HEC-PRM diversion option because the diversion option requires penalty functions to be provided and the optimization of Reclamation's withdrawals was not a part of this study.

Cumulative modified flows (in cfs/month) are converted to 1000 acre-ft/month (kaf) using the program MATHPK to provide the local flow in volume units per time step, as required by HEC-PRM. These flows are disaggregated, based on drainage area adjustments, using data presented in *Appendix to Adjusted Streamflow And Storage* (Columbia River Water Management Group, Depletions Task Force, 1982).

The analysis starting and ending storages are specified assuming that the combined conservation-flood control pool is full. Thus, the analysis starts and ends when snowmelt runoff could be expected to have filled available storage.

Reservoir storage levels are defined as fixed maximum and minimum limits, except at Corra Linn, Albeni Falls, and Kerr. These three reservoirs are described as natural lakes formed by glacial terminal moraines, with release structures located on natural channels some distance downstream from the natural lakes they control. For these reservoirs, an arbitrarily large maximum storage limit is specified. Proper operation of these reservoirs is achieved by limiting outlet capacities and penalty functions which impose high penalties for exceeding the nominal upper storage limit. No limiting outlet capacities are specified for other reservoirs. Storage and release limits are tabulated in Table 3.2.

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The Canadian storage projects Mica, Arrow, and Duncan and the U.S. Libby reservoir are operated under the provisions of Article XV of the U.S.-Canadian Columbia River Treaty. Modeling to achieve this is described in more detail in Chapter 4.

3.3 Penalty Function Refinement

Refined penalty functions for all project purposes were developed by IWR in cooperation with NPD district and division staff. The penalty functions were provided to HEC in January 1993. A selected set of penalty functions for key system locations are provided in Appendix E. The publication, Economic Value Functions for Columbia River System Analysis Model, Phase 2, dated August 1993, prepared by IWR and NPD describe the complete set of these functions in detail.

Penalty functions provided by IWR were combined and edited by HEC to yield the convex piecewise linear penalty functions required for HEC-PRM. For example, a reservoir-recreation penalty function, and a reservoir storage water-supply penalty function may apply for a given reservoir. A composite penalty function is developed by summing penalties for a given storage or flow. A convex, piecewise-linear approximation of the composite function, termed the *edited* function, is developed in the format required for the HEC-PRM analysis. Figure 3.2 illustrates development of a composite penalty function for a single reservoir.
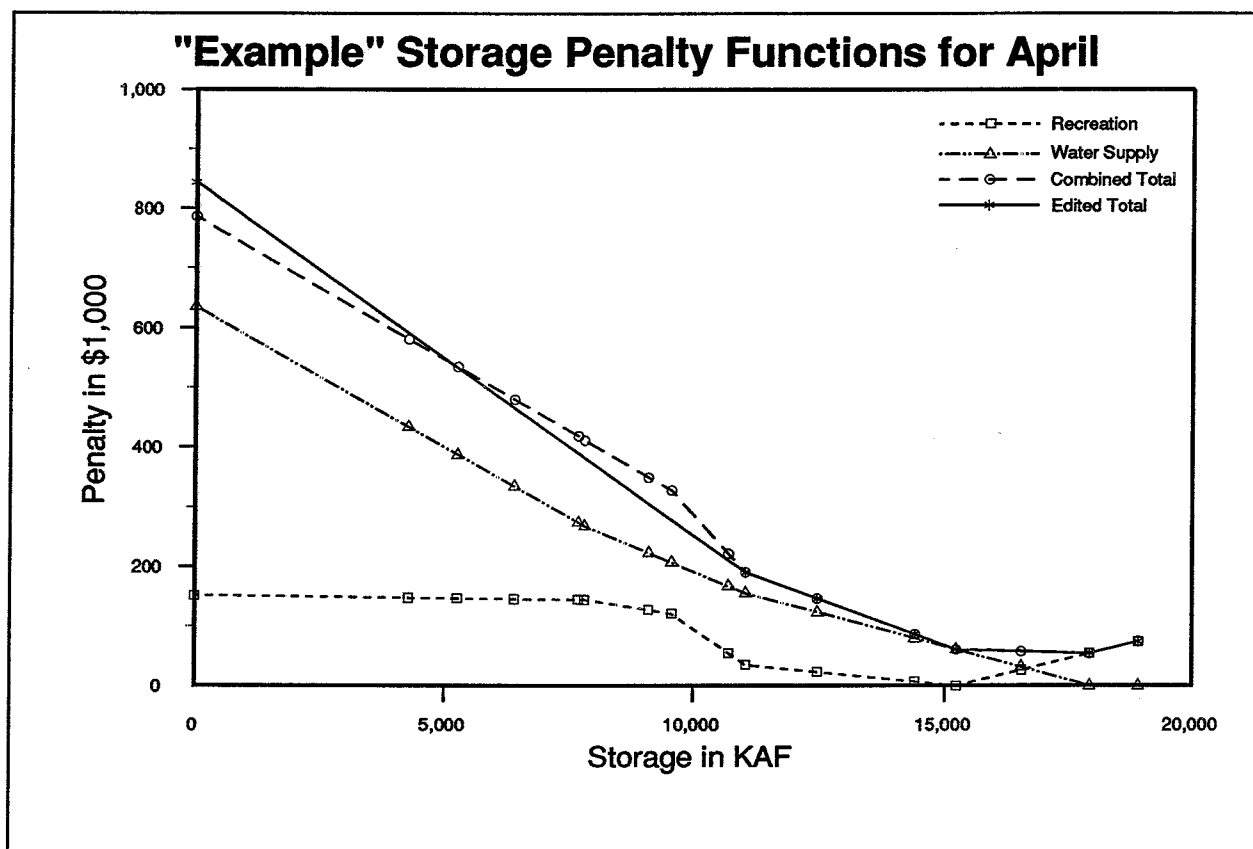

FIGURE 3.2 How Penalty Functions are Combined and Approximated

Phase I hydropower penalty functions for both storage and run-of-river projects were based on a simplified approach that used average reservoir storages. For the Phase II analysis, hydropower penalty functions for storage projects were developed by NPD and IWR (IWR reference) that related hydropower to varied storage. Penalty functions were developed for five pool storage conditions: normal full pool, 25 percent drawdown, 50 percent drawdown, 75 percent drawdown, and normal minimum pool.

Phase II hydropower penalty functions are based on an equal value of firm energy throughout the year; firm capacity value however is varied seasonally. The months were grouped into four seasons based on having peak loads of similar magnitude. The minimum hydropower penalty, however, is the same value for all seasons (zero penalty at hydraulic capacity) thus minimizing the seasonal character of the hydropower penalty functions. Example hydropower penalty functions are shown in Appendix E, Figures E.7 - E.10.

The edited non-hydropower penalty functions were constructed using PENF, a penalty-function graphic editor program (HEC, 1992). PENF retrieves composite penalty functions from HEC-DSS files; displays the function; proposes a convex, piecewise-linear approximation; permits the analyst to adjust the approximation; and stores the selected edited approximation in the appropriate HEC-DSS file.

3.4 Software Improvement

The HEC-PRM general-purpose software package consists of a program manager, a network generator that defines the network-flow programming problem from a reservoir system description, a network solver that solves the minimum-cost generalized network-flow programming problem, a data manager, and display, reporting, and post-analysis software. Significant improvements to the network generator and to the network solver were made for the Phase II Columbia River analysis.

3.4.1 Network-generator Improvements. As described in Appendix A, the HEC-PRM software generates an arc-node model from the user's description of the system. It defines, for each arc of the network, a unit penalty for flow on the arc. Such a simple penalty adequately represents most system purposes. However, hydropower production is not a simple linear function of release, storage, or flow. Instead, production, and hence penalty for lack of production, is a nonlinear function of both release *and* storage.

The Phase I study applications used simplified hydropower penalty functions. Average storage was assumed for each reservoir in each period. Thus the nonlinear penalty was represented as a linear function of reservoir release only for a given storage.

For the analysis reported herein, the HEC-PRM network generator was modified to eliminate the simplification used in Phase I. This was accomplished by incorporating a successive linear programming (SLP) algorithm to solve the nonlinear hydropower optimization problem. Appendix B describes the algorithm in detail.

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3.4.2 Network-solver Improvements. For Phase I analyses, HEC-PRM used a generalized network solver acquired from the Texas Department of Water Resources (Martin, 1982). For Phase II, the solver was replaced with a more efficient solver (Jensen, 1991a and 1991b). The new solver incorporates the following special features to accommodate the reservoir-system network structure:

A special data structure to store unit costs and bounds required for the piecewise-linear approximation of nonlinear penalty functions. This greatly reduces hardware memory requirements, permitting analysis of large systems.

Provision for known reservoir inflows and local flows. This eliminates the need for arcs that represent reservoir inflows and local flows. This reduces computer storage requirements and speeds solution of the problem.

Capability to use efficiently a previously-found solution to restart. This is particularly useful for the successive linear approximations required for hydropower penalty computation. In that case, the network problem changes only slightly from one linear approximation to the next. This capability eliminates the need to "start from scratch" to find the optimal flows at each iteration.

The FORTRAN code of HEC-PRM was restructured as necessary to accommodate the new solver. However, the modified version of HEC-PRM is upwardly compatible with all existing input.

3.5 Technology Transfer

3.5.1 User Documentation. HEC-PRM's user documentation, developed for the Missouri River System operation study (HEC, 1992) was deemed to be sufficient for the Columbia River study.

3.5.2 Workshop. HEC staff conducted a workshop for NPD staff in August 1993, prior to the anticipated publication of this report. Materials from that workshop will be published under separate cover.

Chapter 4

System Operation Analysis: Comparison of Alternatives

This chapter begins with a brief overview of the existing operation strategy for the Columbia River System, a strategy embodied in the HYSSR model and its results. The alternative operating conditions, specified by NPD, are then presented. Operation for each alternative was prescribed by HEC-PRM. The performance and operation results from these three alternatives and HYSSR are then compared for operation over the adopted 1928 - 1978 record period. Comparisons are made for the subsystem upstream of Grand Coulee, the subsystem upstream of Lower Granite, and the system upstream of The Dalles. Overall results are then summarized and discussed.

4.1 Existing Operation Strategy

The Columbia River reservoirs are operated as a system to maximize their benefits. The system has about 37,000,000 acre-feet of storage space that can be effectively used for mainstream control. This volume represents about 30 percent of the average annual runoff at The Dalles. Reservoirs east of the Cascades, the subject of this study, are held as full as possible during the summer to enhance recreation and conserve water for later uses. Some release of reservoir storage may occur during this period for irrigation, water supply, and power generation.

Drafting of the reservoir system occurs early in the fall after temperatures and streamflows begin to drop. During this time, power demand increases and recreational uses at the lakes decrease. Drawdown must also begin in the fall to provide storage for winter flood control. The reservoirs reach their lowest levels in March to early May. Snowmelt typically begins to increase in mid-April and peaks in June. A portion of the high runoff is stored to refill the reservoirs and regulate downstream flooding. Detailed discussion of Columbia River operations is contained in U.S. Army Corps of Engineers (1984).

4.1.1 Operation Rules. Operation rules are developed at the start of the operation year and updated (normally monthly) as the year progresses and more information on the snowpack and streamflows become available. Operation rules are established yearly and updated more frequently for individual reservoirs and the coordinated system. The system's operating year can be divided into three seasons.

August through December, fixed drawdown. During this period, reservoirs are operated according to predetermined rules because runoff forecasts from snowpact are not available until January.

January through March, variable drawdown. During this period, operation of the reservoirs is guided by runoff forecasts. Reservoirs are drafted to provide flood control space

and to meet power demands. They are drafted to generate as much additional energy as possible while maintaining sufficient storage to meet spring fish flows and to ensure a high likelihood of reservoir refill by summer. Figure 4.1 illustrates typical operation rule curves.
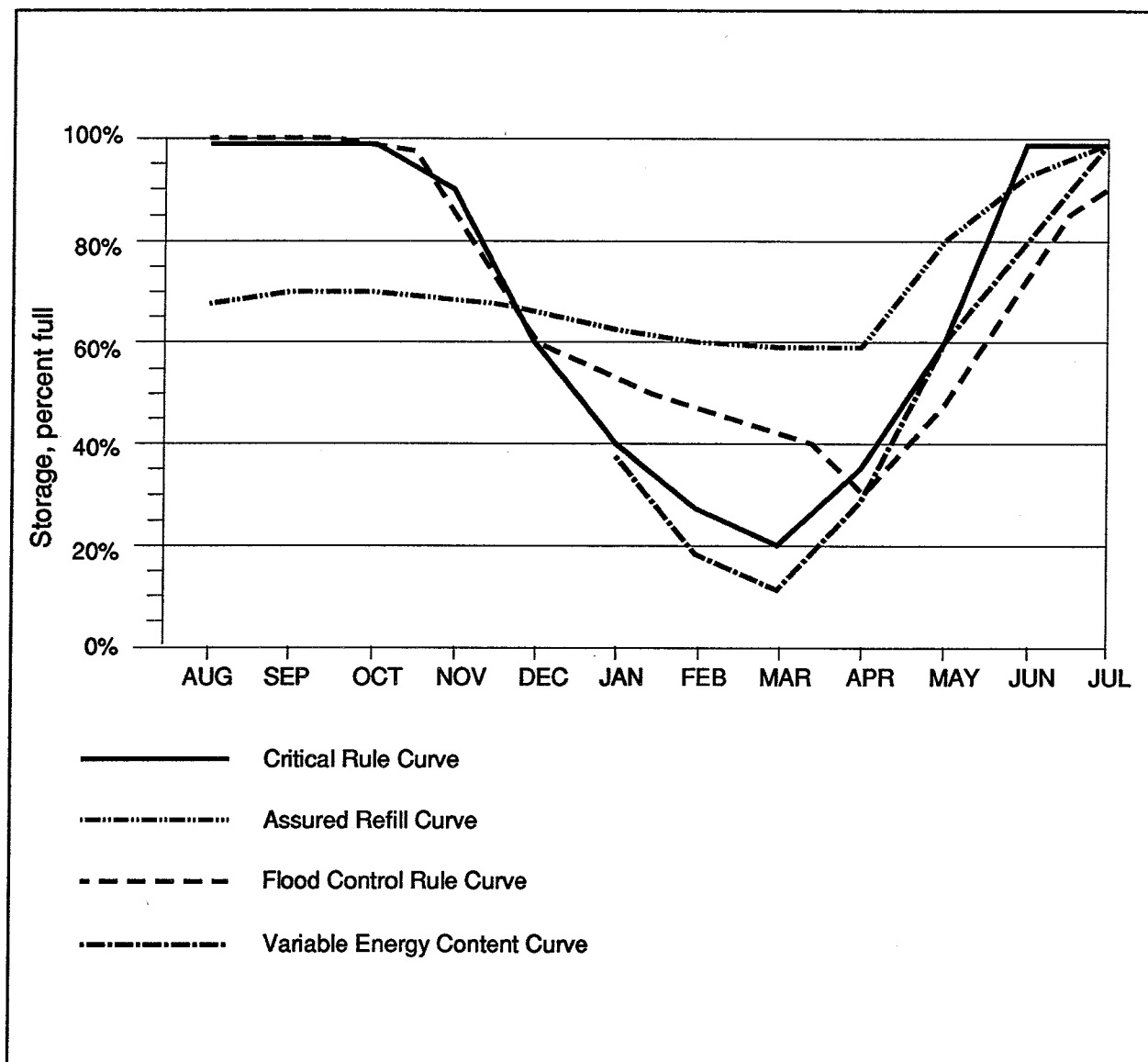
FIGURE 4.1 Illustration of Operating Rule Curves

April through July, reservoir refill. Spring runoff is stored and flood peaks clipped during this period. Water is released to help juvenile salmon and steelhead migration to the ocean. Operation for flood control and power sales continue as needed. (U.S. Department of Energy, et al. 1991)

4.1.2 Overview of Water Control Goals by Purpose. Each project purpose requires its own methods for system regulation. Some purposes require the use of water stored in the

reservoirs to augment natural streamflow for hydroelectric power, irrigation, navigation, municipal and industrial use, and fish and wildlife. These operations are performed using rules derived from analysis of historic records and updated seasonally as described earlier (Figure 4.1). These rules define the limits of operation on a monthly basis.

Hydropower Regulation. Rules for water supply and hydropower regulation for the early reservoir drawdown period are usually close to the critical year rule curve or lower storage limits. This provides additional system capacity which can be used to meet secondary energy needs. After January 1st, seasonal runoff normally enables modification of the rule curves.

Flood Control. Requirements for flood control operation are determined annually, primarily on the basis of forecasts of seasonal runoff. These requirements vary significantly from year to year. The rule curves developed form the upper limits of the permissible reservoir regulation levels. The refill from May through July is based on individual project flood control operation criteria.

Irrigation. Reservoirs in the Columbia River System serving irrigation are primarily operated by the Bureau of Reclamation. Irrigation normally has a minor effect on overall system operation. However, irrigation pumping at Grand Coulee Project has a major impact on Columbia River System operation as defined in Chapter 3. Irrigation water supply reservoirs are operated by capturing all runoff in excess of minimum flow demands during the spring and early summer. Water is retained in storage until natural runoff cannot meet irrigation demands (usually near the end of June). Releases then meet irrigation demands through the end of the growing season, normally in September. Minor irrigation releases may occur through the winter season.

Navigation. The Columbia-Snake River waterway form the Pacific Ocean to Lewiston, Idaho, includes a 40-foot depth open river deep-draft channel for ocean vessels to Vancouver, Washington, and a 14-foot deep barge channel from Vancouver to Lewiston. The barge channel is provided by the eight-dam complex of navigation locks and dams extending from Bonneville to Lower Granite. Natural river flows, augmented during the low flow period for power production, normally meet deep-draft navigation requirements with augmentation required in late summer or early fall. This has only a minor system effect. However, barge navigation requirements are local and may constraint operation at some hydropower sites.

Recreation. Recreational use of reservoirs is almost entirely from late June through early September. The major recreation objective is to maintain reservoir pools near capacity during this period without harming other major purposes. Conflicts with flood control and power regulation may occur. For example, flood control operation in June may delay filling the reservoirs while evacuation of water for power in August may disturb recreation in late summer.

Fish Protection. Regulation for fish protection has taken on greater significance as the completion of dams has eliminated most open river reaches above Bonneville Dam on the Columbia and to Lewiston on the Snake. The major salmonid migration both upstream and downstream occurs during the spring and early summer when natural flows are high. Prior to

the dams, the juveniles' travel time through the now impounded reach of river was about 10 days. With the projects in place and the corresponding reduced velocities, the travel time can approach 40 days. This results in greater losses due to predation, reduced passage for upstream migration, and passage of juveniles through the turbines during downstream migration.

To offset fish losses, drafting of storage projects for power during the winter has been reduced to provide more water for the run-of-river projects beginning in mid-April for the major downstream juvenile migration. (USACE, 1984)

4.1.3 Hydro-System Seasonal Regulation (HYSSR) Model. The computer program used by NPD in performing long-range analysis of the reservoir system, primarily in connection with hydropower evaluation, is the HYSSR model. The operation of the model is based on mean monthly conditions of flow, reservoir levels, and power generation. The model uses mean-monthly streamflows predetermined for each project or control point.

4.2 Analysis Overview

The Phase II operation analysis evaluated Columbia River System operation for the adopted standardized 50-year period of 1928 to 1978 for three alternatives: (1) operation with existing objectives and existing Canadian treaty storage; (2) operation without the hydropower objective, and (3) operation with additional Canadian treaty storage. Each alternative is modeled by altering the system penalty functions and/or constraints in the network representation with HEC-PRM. The alternatives were specified by NPD.

System performance for the alternatives is compared in two ways: performance with current operation rules, as defined by simulation with the HYSSR model executed in the continuous mode, compared to HEC-PRM Alternative 1; and HEC-PRM Alternatives 1, 2, and 3 compared to one another. Alternative 1 is the HEC-PRM model equivalent to the HYSSR model results identified as "HM9091A2 - SOR base case." Both are intended to reflect existing conditions and system objectives. A perfect match of results was not expected. Indeed, the results were not expected to be identical as the models employ different simplifications and representations of the prototype. HYSSR model results are used in the comparison because they reflect in detail, the physical constraints and goals of the present system and are well understood and considered dependable by NPD.

4.3 Description of Alternatives

4.3.1 Alternative 1: Operation with Existing Canadian Treaty (Present Conditions). This alternative includes the following:

Storage nodes for ten U.S. reservoirs and four Canadian reservoirs plus eight non-storage nodes. This is the system illustrated by Figure 3.1.

Penalty functions represent all present system goals and priorities, including hydropower, at all U.S. storage projects. Brownlee, an Idaho Power reservoir, has only hydropower penalties.

Operation constraints and penalty functions to model operation of the Canadian reservoirs according to provisions of the Columbia River Treaty. In this treaty, the U.S. and Canada agreed that Canada would construct Mica, Arrow, and Duncan dams. These would "... provide 15,500 kaf of storage for power, and 8,450 kaf of primary storage, together with 12,000 kaf of secondary storage for flood control." (USACE, 1984) The Treaty provided that Canada would operate the projects for flood control and optimal power generation downstream. No penalty economic functions were available for the Canadian reservoirs. However, for Arrow and Duncan, minimum releases of 5,000 cfs and 100 cfs are included, respectively. Duncan also has a release penalty function which encourages releases to be less than 20,000 cfs which is a downstream channel capacity. For Mica, a release penalty function was developed to encourage operation with a minimum flow of 10,000 cfs on a seasonal basis and a maximum of 41,600 cfs. This provides a realistic operation based on physical characteristics in the absence of economic penalty functions. Similarly, desired operation of Corra Linn is defined with a storage penalty function that discourages storage above the flood-control rule curve agreed to by the International Joint Commission (IJC). Thus, storage will only occur above the IJC specified rule curve when outlet capacity restricts operation.

4.3.2 Alternative 2: Operation without Hydropower Objectives. This alternative is identical to Alternative 1 except that hydropower penalties are eliminated and replaced with very minor non-economic penalties which encourage releases within the physical limits of the projects.

In preliminary runs, it was observed that it was necessary to add minimum release limits to avoid zero releases at several storage projects. The specified minimum releases were included in all alternatives and are shown in Table 3.2. The non-economic penalty functions and minimum releases were added to achieve a reasonable range of results.

4.3.3 Alternative 3: Operation with Additional Canadian Treaty Storage. This alternative includes all system components. Penalty functions and operation constraints for all U.S. projects are the same as with Alternative 1 and an additional five million acre-feet of storage is made available at Mica reservoir in Canada.

4.4 Comparison of Alternatives

4.4.1 General. Results of the HEC-PRM analysis include optimized operation for each of the three alternatives. Post-processed results include monthly tabulation of time-series data for each purpose penalty (hydropower, flood control, fish protection, navigation, irrigation, and recreation) and for system flows and reservoir storages. Storages and flows were prescribed by HEC-PRM at selected locations in the system, along with operation

simulated with HYSSR for the period of 1943 through 1949. This period has both a low flow (1943) and high flow (1948) period. The entire 50-years of analysis for selected locations are shown in Appendix F. Appendix G shows system time-series results of hydropower energy production prescribed by HEC-PRM.

4.4.2 Measures of Performance. Four indices are used to summarize the performance of each alternative for each system sub-system purpose. Each index represents a different dimension of performance (Hashimoto, et al., 1982). These indices are presented in more detail in Table 4.1.

Penalty is the raw economic impact derived from the economic and non-economic penalty functions used in HEC-PRM.

Reliability is the frequency that performance fails to meet a particular purposes's target.

Resiliency is a measure of a system's ability to recover from failure. The resiliency index used here is the number of recoveries divided by the number of failing months, expressed as a percent.

Vulnerability indicates the magnitude of typical failures, when they occur. Here, the average deviation from a performance target is used.

These performance measures are defined in greater detail in Table 4.1.

The results are discussed for two strategic subsystems and for the system upstream of The Dalles. The first subsystem is the Columbia River upstream of Grand Coulee. The second subsystem is the Snake River at the combined node including Lower Granite/Little Goose/Lower Monumental/Ice Harbor referred to as Lower Granite. The combined node of Bonneville/The Dalles is referred to as The Dalles. Similar information for other locations can also be developed.

4.5 Columbia River at Grand Coulee

Projects upstream of Grand Coulee Dam are on the Clark Fork, Pend Oreille, Flathead, Kootenai, Duncan and main stem Columbia Rivers. The HEC-PRM analysis included eight storage projects above Grand Coulee Dam with 36,700,000 ac. ft. of active storage including Grand Coulee. Of this, 20,900,000 ac. ft. are Canadian project storage. Mica, the largest reservoir in the Columbia system, has the majority of the Canadian storage. There are 74,100 sq. mi. of drainage area above Grand Coulee Dam with a mean annual runoff of 78 million acre-feet. Grand Coulee is the largest U.S. project in the Columbia River System, and is the farthest downstream project with significant storage on the Columbia River. As such, its operation is critical to downstream flow conditions both before and after the confluence of the Snake River, a major tributary. (USACE, 1984)

TABLE 4.1
Performance Indices Definition

Penalty. Penalty is computed from the individual purpose penalty functions. The computations use flow and storage results from model output. The total is the sum of the purpose penalties. Because the individual purpose penalties are derived from economic benefit analysis, the penalties tabulated can be interpreted as economic costs of operation. Differences in penalties between alternatives can therefore be interpreted an increase or decrease in system economic benefits.

Reliability. This is the frequency of meeting the monthly target. Reliability of 100% implies that the monthly target is always met; reliability of 0% implies that it is never met. The monthly target is defined as follows:

Flood control: maximum flow with zero damage;

Fish protection: minimum flow indicated by lowest point on the penalty function;

Navigation: storage range indicated by the lowest point on the penalty function;

Irrigation: at least 80% of requirement;

Recreation: flow or storage range indicated by lowest point on penalty function.

These targets are identified by referring to NPD-specified system operation targets or to the penalty functions (which should reflect the targets). For hydropower, NPD provided monthly system-wide hydropower demands that were used with HYSSR.

Resiliency. This is the frequency of recovering from failing to meet the target in the previous month. Resiliency of 100% implies that the system always recovers: in no two successive months does the system fail to meet the target. Resiliency of 0% implies that once the system fails to meet the target, it never recovers.

Vulnerability. This is the average monthly deviation from the target when a deviation occurs. Deviation is defined here as follows: for flood control, difference between actual flow/storage and target; for fish protection, difference between actual flow/storage and target; for navigation, difference between actual flow/storage and minimum if less than target or maximum if greater; for water supply, difference between actual flow/storage and target; for recreation, difference between actual flow/storage and minimum (if prescribed value is less than target) or maximum (if prescribed value is greater than target); for hydropower, difference between actual production and demand (computed for the entire system only). All values of flow and storage are displayed in kaf and hydropower value are in MW. (Hashimoto, et al, 1982)

4.5.1 System Operation Upstream of Grand Coulee. Figure 4.2 (*a, b, c*) shows the prescribed storage, in kaf, at Mica reservoir for Alternatives 1, 2, and 3, respectively. Figure 4.2 (*c*) shows that the reservoir is drafted heavily in May, June, and July of 1944 - 1947 with Alternative 3, making additional water available for downstream use. This reflects the additional Canadian storage available with this alternative. The analysis provides that an additional 5 million acre-feet of storage is available (with only physical release penalties) for the needs of the downstream U.S. system. Appendix F, Figures F.1 through F.5, clearly shows the difference in operation levels of Mica for Alternatives 1 and 3. An effect is a more stable pool for Grand Coulee, discussed later. Figure 4.2 (*b*) illustrates the impact of omitting the power objectives: Water is stored in Mica reservoir during the low flow period of 1944, as it is not needed for hydropower generation downstream.

4.5.2 Grand Coulee Operation. The HEC-PRM time-series analysis results for the HYSSR and three alternatives at Grand Coulee are shown on Figure 4.3 for 1943 through 1949, and in Appendix F for the 50 years of analysis. The results clearly show the current annual drawdown cycle, depicted by the HYSSR results, with significantly less drafting of the storage required for HEC-PRM operation for the three alternatives studied. Alternatives 1 and 3 have nearly identical patterns, with Alternative 2 being somewhat similar. Figure 4.3 (*a*) shows the prescribed storage, in kaf, at Grand Coulee with Alternative 1. Operation with Alternative 2 is shown in Figure 4.3 (*b*). Figure 4.3 (*c*) shows the storage prescribed with Alternative 3. Operation with Alternatives 1 and 3 is similar, except that with the additional storage at Mica, drafting from maximum storage is postponed briefly. Operations for Alternative 2 are different in 1945 and 1946 because of non-hydropower needs. Operation in 1948 is similar with all alternatives, as necessary to provide flood control during this time of high runoff.

The percent monthly exceedance relationship of reservoir storage shown on Figure 4.4 indicates these differences quantitatively. The HYSSR results indicate that the reservoir is full to near full less than 45% of the time, whereas the optimization results maintain a full pool 85-95% of the time. The hydropower generation benefits from the generally fuller reservoir but even Alternative 2, without the hydropower objective, keeps the Grand Coulee pool level full a significant percent of the time. This difference can be explained by the relatively free Canadian water (no penalties) and the capability of HEC-PRM to operate with perfect knowledge in time and space. This explanation is supported by the results of Alternative 3 presented in Figure 4.4, where additional Canadian Treaty storage results in a still greater tendency to store water in Grand Coulee. The HYSSR reflects limited forecasting capability, seasonal at best, and thus the need to draw down the system for potential flood events.

The annual (January - December) and fish season (April - July) flow-exceedance frequency relationships for Coulee releases are shown on Figures 4.5 and 4.6, respectively. The annual plots show a generally consistent result except that HYSSR has significantly greater flows in the 0-10% range and Alternatives 1 and 3 maintain higher flows for the 75-100% range, due primarily to meeting hydropower demands. The fish-release season operations show a substantial difference between the three alternatives and HYSSR results. The HYSSR graph shows significantly higher flows from 0-10%, while the three alternatives
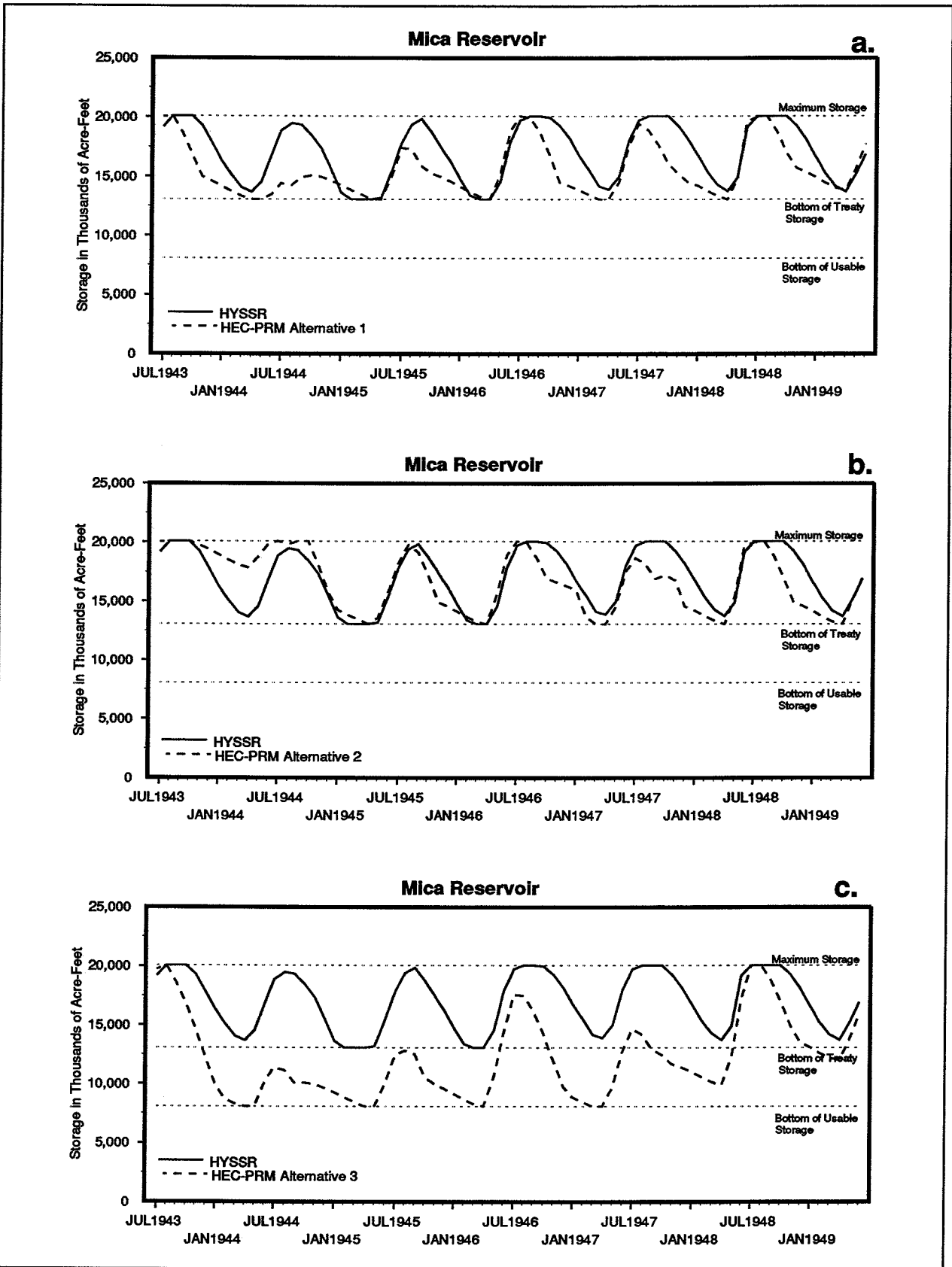
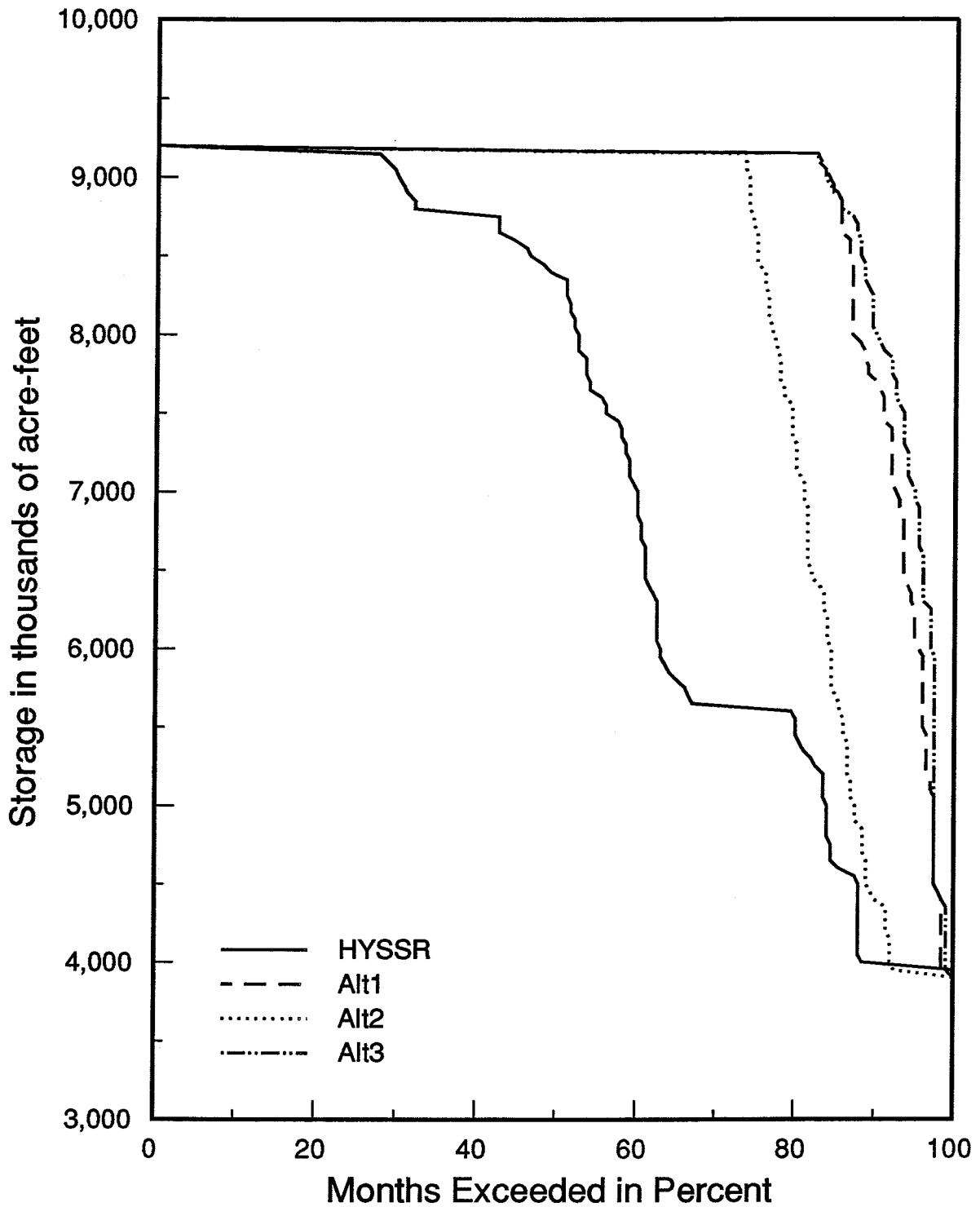**FIGURE 4.2 1943 - 1949 Storage at Mica: HYSSR & Alternatives**

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FIGURE 4.4 Percent Time Exceedance for Grand Coulee Storage (April - July)

Grand Coulee Flow
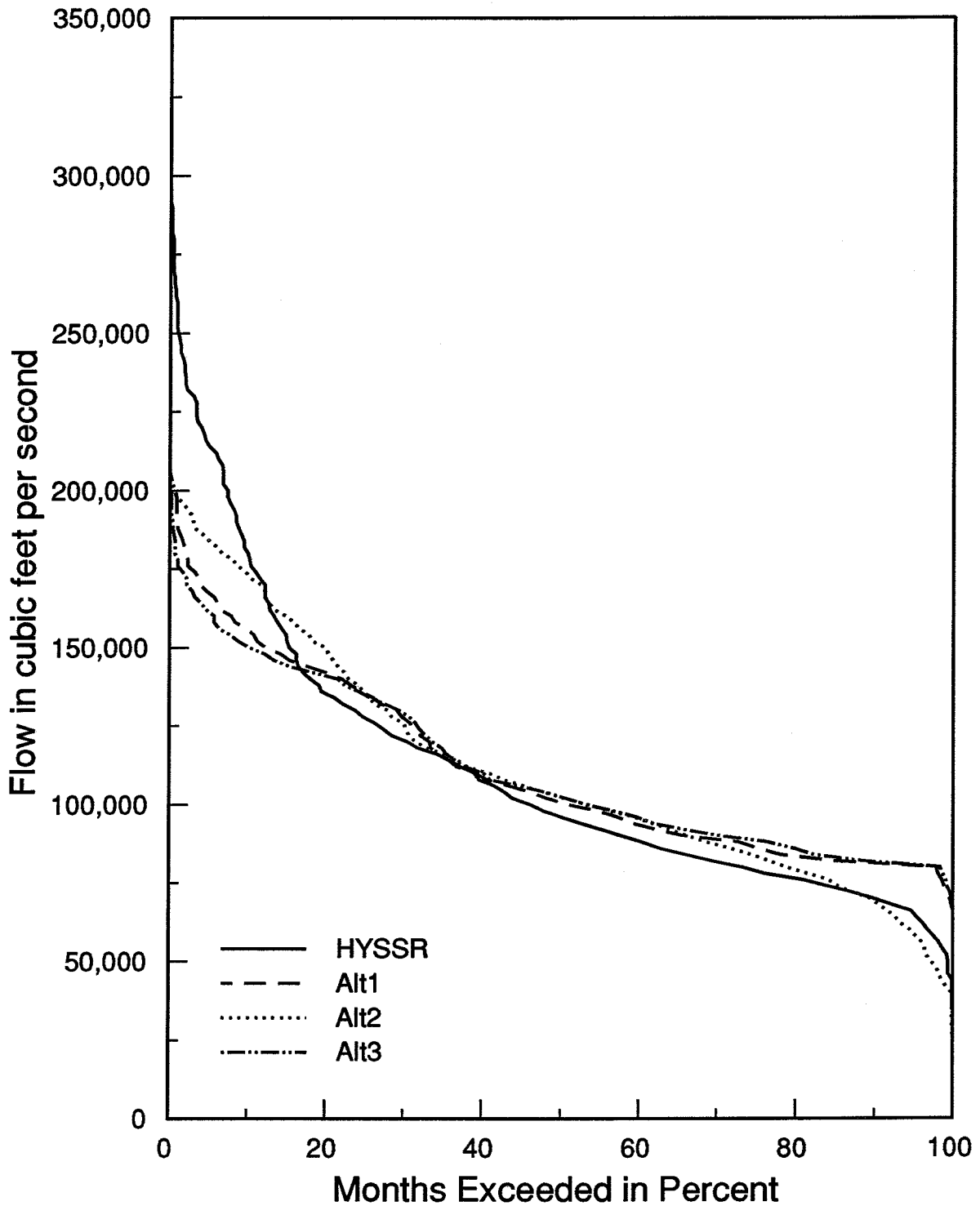## January through December

FIGURE 4.5 Exceedance Frequency for Grand Coulee Releases (January - December)
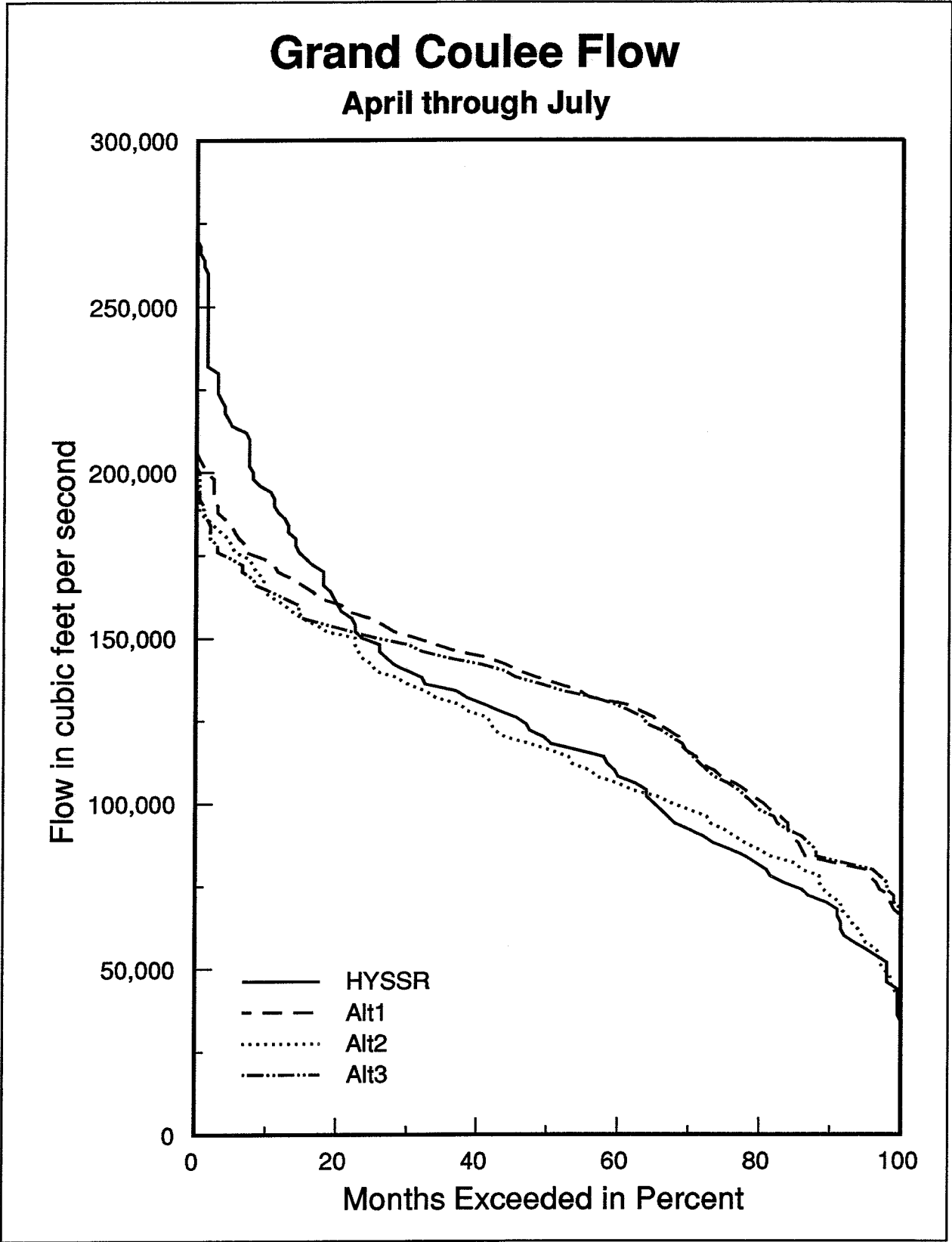
FIGURE 4.6 Exceedance Frequency for Grand Coulee Releases, Fish-flow Season
(April - July)

maintain consistently higher flows over the remainder of the range. Eighty thousand cfs or higher is met by the three alternatives approximately 92% of the time and 80% of the time for HYSSR.

4.5.3 System Performance Above Grand Coulee. Performance indices for each alternative may be developed which show the sum of penalties for each purpose and total penalty for all purposes, and indices labeled reliability, resiliency, and vulnerability (Hashimoto, et al., 1982). These indices were formulated to provide a general summary basis for characterizing operation and comparing alternative performance. The indices are defined in Table 4.1. The indices for hydropower are shown only for The Dalles since the hydropower demand needed to compute the indices is known only for the total system.

Table 4.2 presents the performance indices measured for the sub-system above Grand Coulee. With current operation, as simulated with HYSSR, total penalty is 58.75 billion dollars units, 99% of which is penalty for failing to operate ideally for the hydropower penalty functions defined. This is curious, as current rules were selected for efficient hydropower production with current demands. Comparison of the penalty functions used with HEC-PRM and the hydropower loads used with HYSSR yields an explanation. The hydropower penalty functions used with HEC-PRM do not have a significant seasonal variation, but the hydropower demands in the system do vary seasonally. This was a conscious choice in developing the hydropower penalty functions. This might be reconsidered in light of the results. Further, the hydropower demands include a demand that is a surrogate for releases for fish protection. Further, separable hydropower penalty functions are defined for each reservoir with HEC-PRM, while the hydropower demands simulated with HYSSR are system-wide. Thus is it possible that operation that meets specified system-wide demands will be nonoptimal when measured against the penalty functions. This is true for other subsystems and the entire system as well.

The hydropower penalty is similar for Alternatives 1 and 3, with Alterative 3 being slightly less. With Alternative 2, hydropower penalty increases. This is expected, as Alternative 2 focuses on operation for all other purposes; the hydropower generated is incidental from operation for the other purposes.

For this subsystem, current HYSSR rules meet flood-control needs 76% of the time. When operation with these rules fails to meet the flood control targets in a given month, the system is able to recover in the following month only 23% of the time. Alternative 2 is inferior to 1 and 3 for each of the 3 indices for flood control, although it has the lowest flood control penalties. In this case, flood control targets may be set low, since failures occur relatively frequently compared to the target, but with little penalty.

The Alternatives 1, 2, and 3 are superior in meeting recreation demand compared to current operation. However, when a failure occurs with Alternative 2, it is more serious on average.

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TABLE 4.2

Comparison of Performance: System Upstream of Grand Coulee Node (inclusive)

Performance index (1)	HYSSR Operation (2)	Alternative 1 (3)	Alternative 2 (4)	Alternative 3 (5)
Penalty, $ millions for (50-year record)				
Total	58,753.0	54,557.0	58,223.5	54,413.4
Hydropower	58,220.0	54,417.9	58,078.6[1]	54,289.6
Flood control	84.4	52.9	30.7	49.9
Fish protection	N/A[2]	N/A	N/A	N/A
Navigation	N/A	N/A	N/A	N/A
Irrigation	324.7	53.9	79.2	43.8
Recreation	124.2	32.6	35.3	30.5
Reliability, in %				
Hydropower	N/A	N/A	N/A	N/A
Flood control	82.9	86.6	83.8	86.4
Fish protection	N/A	N/A	N/A	N/A
Navigation	N/A	N/A	N/A	N/A
Irrigation	48.0	56.7	56.2	57.5
Recreation	15.6	37.8	42.0	38.1
Resiliency, in %				
Hydropower	N/A	N/A	N/A	N/A
Flood control	23.1	28.3	22.9	27.0
Fish protection	N/A	N/A	N/A	N/A
Navigation	N/A	N/A	N/A	N/A
Irrigation	29.8	33.5	44.5	35.7
Recreation	7.0	15.4	19.6	15.2
Vulnerability				
Hydropower, MW	N/A	N/A	N/A	N/A
Flood control, kaf	469.3	524.9	687.3	511.8
Fish protection, kaf	N/A	N/A	N/A	N/A
Navigation, kaf	N/A	N/A	N/A	N/A
Irrigation, kaf	2,159.7	1,567.5	1,753.7	1,499.5
Recreation, kaf	1,518.2	1,338.0	1,881.7	1,301.3

[1] Hydropower penalty computed via post-processing based on HEC-PRM results without hydropower objective and hydropower penalty functions.

[2] N/A - Not applicable; Purpose does not exist or penalty functions were not provided for analysis.

4.6 Snake River Upstream of Lower Granite

The Lower Granite node includes Lower Granite, Ice Harbor, Lower Monumental, and Little Goose on the lower Snake River. Upstream storage projects include Dworshak on the Clearwater River and the Brownlee, Oxbow, and Hells Canyon node on the Snake River. The Snake River at the Lower Granite node has a drainage area of approximately 109,000 sq. mi. with 34 million ac. ft. of annual runoff. Dworshak has slightly over two million ac. ft. of active storage. Brownlee, the largest downstream storage project on the Snake River, has slightly under one million ac. ft. of active storage. Operation of these two projects affects the Lower Granite node on the lower Snake River, and The Dalles node on the lower Columbia River. (USACE, 1984).

4.6.1 Performance of System Upstream of Lower Granite. Figure 4.7 (*a*) shows 1944 releases prescribed for Lower Granite reservoir with Alternatives 1 and 2. Clearly if power is omitted, as with Alternative 2, the releases are greater in April, May, and June. The releases prescribed correlate with the inflection points of the penalty function, shown in Figure 4.7 (*b*). The unit penalty is great for flows less than approximately 70,000 cfs and for flow greater than 140,000 cfs. With Alternative 1, the hydropower penalties at The Dalles and elsewhere in the system are greater and offset the penalty for failing to make releases in the desired range. However, without the hydropower penalties, the penalty for failing to make releases in this range is great, controlling the operation.

The performance indices computed for this subsystem are shown in Table 4.3. Alternative 1 compared to HYSSR shows reduced hydropower penalty, increased fish protection penalty, similar penalties for navigation, increased penalty for irrigation, and similar recreation penalty values. Indices reflect similar differences with increased resiliency for recreation as the notable improvement, although the value is still very low.

Alternative 2, compared to 1 and 3, shows the expected increase in hydropower penalty and notable reduction in penalties for the other purposes. Flood control is not a significant issue in the subsystem. Fish protection is similar in reliability but shows slightly higher resiliency, and less vulnerability. Navigation shows an increase in reliability and resiliency (doubling) and substantial decrease in vulnerability, all reflecting a favorable improvement. Irrigation reliability is 100% for all alternatives. Recreation is markedly improved for Alternative 2 over Alternatives 1 and 3.

4.6.2 Dworshak and Brownlee Operation. The annual percent time exceedance - storage relationships for Dworshak and Brownlee are shown on Figures 4.8 and 4.9, respectively. The Dworshak pattern is very similar for HYSSR and Alternatives 1 and 3. The pool is full less than 10% of the time, being drawn down for hydropower generation. The curve for Alternative 2 (without hydropower) is substantially different, with the reservoir pool kept essentially full about 65% time due to the recreation and navigation (logging) objectives.
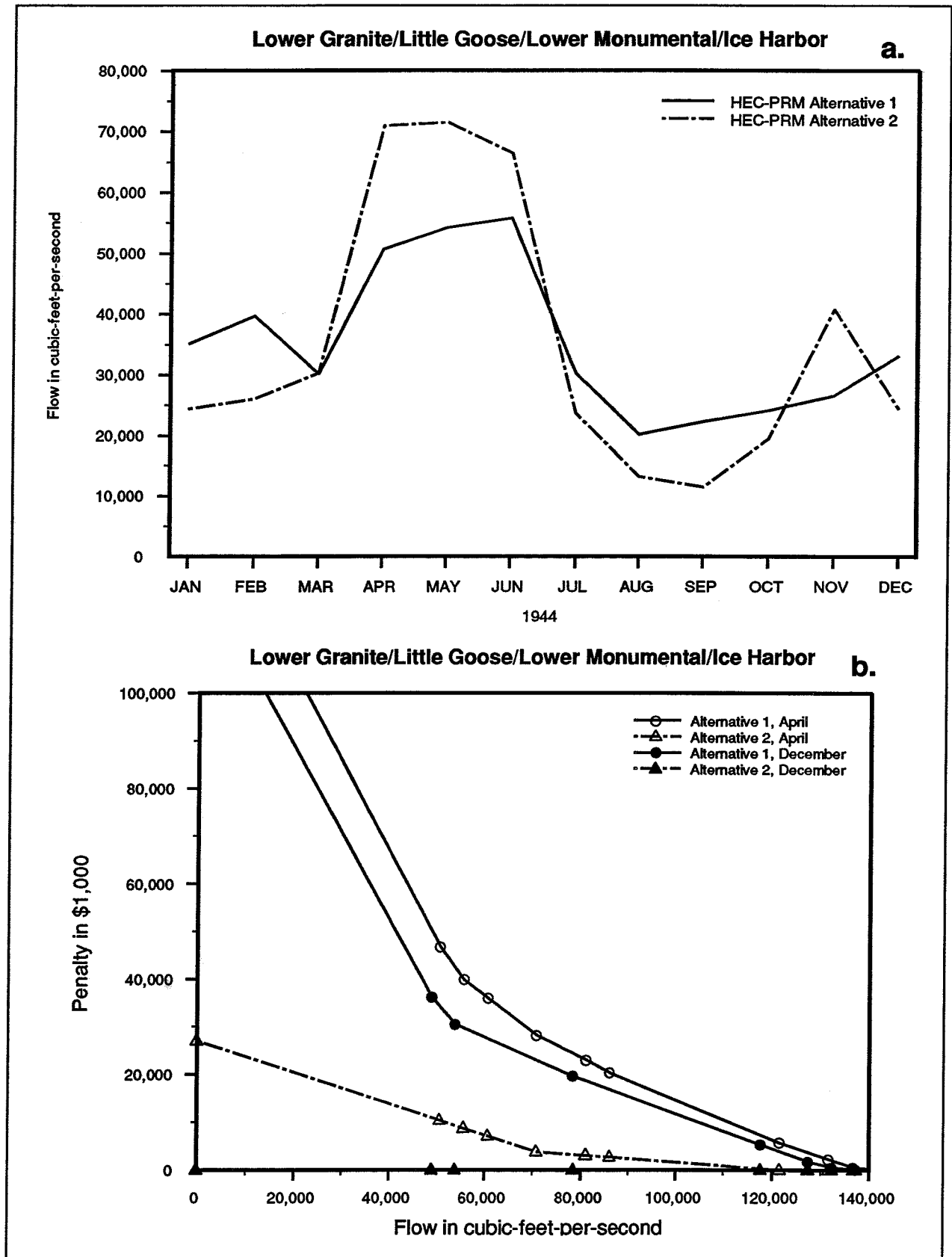
FIGURE 4.7 Penalty Function at Granite: Alternatives 1 & 2

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TABLE 4.3
Comparison of Performance: System Upstream of Lower Granite Node (inclusive)

Performance index (1)	HYSSR Operation (2)	Alternative 1 (3)	Alternative 2 (4)	Alternative 3 (5)
Penalty, $ million for (50-year record)				
Total	36,953.0	34,778.8	37,779.6	34,777.7
Hydropower	36,375.0	34,144.9	37,498.3[1]	34,148.7
Flood control	0.3	0.1	0.1	0.1
Fish protection	491.3	540.5	261.0	536.5
Navigation	79.2	76.0	11.5	75.7
Irrigation	0.0	10.0	5.8	9.4
Recreation	6.9	6.9	2.7	7.1
Reliability, in %				
Hydropower	N/A[2]	N/A	N/A	N/A
Flood control	97.2	97.7	98.0	97.7
Fish protection	77.5	78.8	81.3	79.0
Navigation	81.8	81.5	95.9	81.5
Irrigation	100.0	100.0	100.0	100.0
Recreation	53.2	52.5	69.1	52.2
Resiliency, in %				
Hydropower	N/A	N/A	N/A	N/A
Flood control	88.2	85.7	83.3	85.7
Fish protection	38.5	44.9	52.7	44.4
Navigation	37.4	44.6	80.0	44.1
Irrigation	N/A	N/A	N/A	N/A
Recreation	5.0	12.5	31.3	12.2
Vulnerability				
Hydropower, MW	N/A	N/A	N/A	N/A
Flood control, kaf	395.6	345.5	347.7	345.5
Fish protection, kaf	2,242.4	2,527.4	2,061.2	2,542.1
Navigation, kaf	502.3	427.2	289.8	430.4
Irrigation, kaf	N/A	N/A	N/A	N/A
Recreation, kaf	850.6	922.7	545.5	917.9

[1] Hydropower penalty computed via post-processing based on HEC-PRM results without hydropower objective and hydropower penalty functions.

[2] N/A - Not applicable; Purpose does not exist or penalty functions were not provided for analysis.
1932) the HEC-PRM optimal operation significantly would miss the energy load in three periods, although the average annual energy generated would meet the energy load.

FIGURE 4.8 Exceedance Frequency for Dworshak Storage (January - December)

FIGURE 4.9 Exceedance Frequency for Brownlee Storage (January - December)

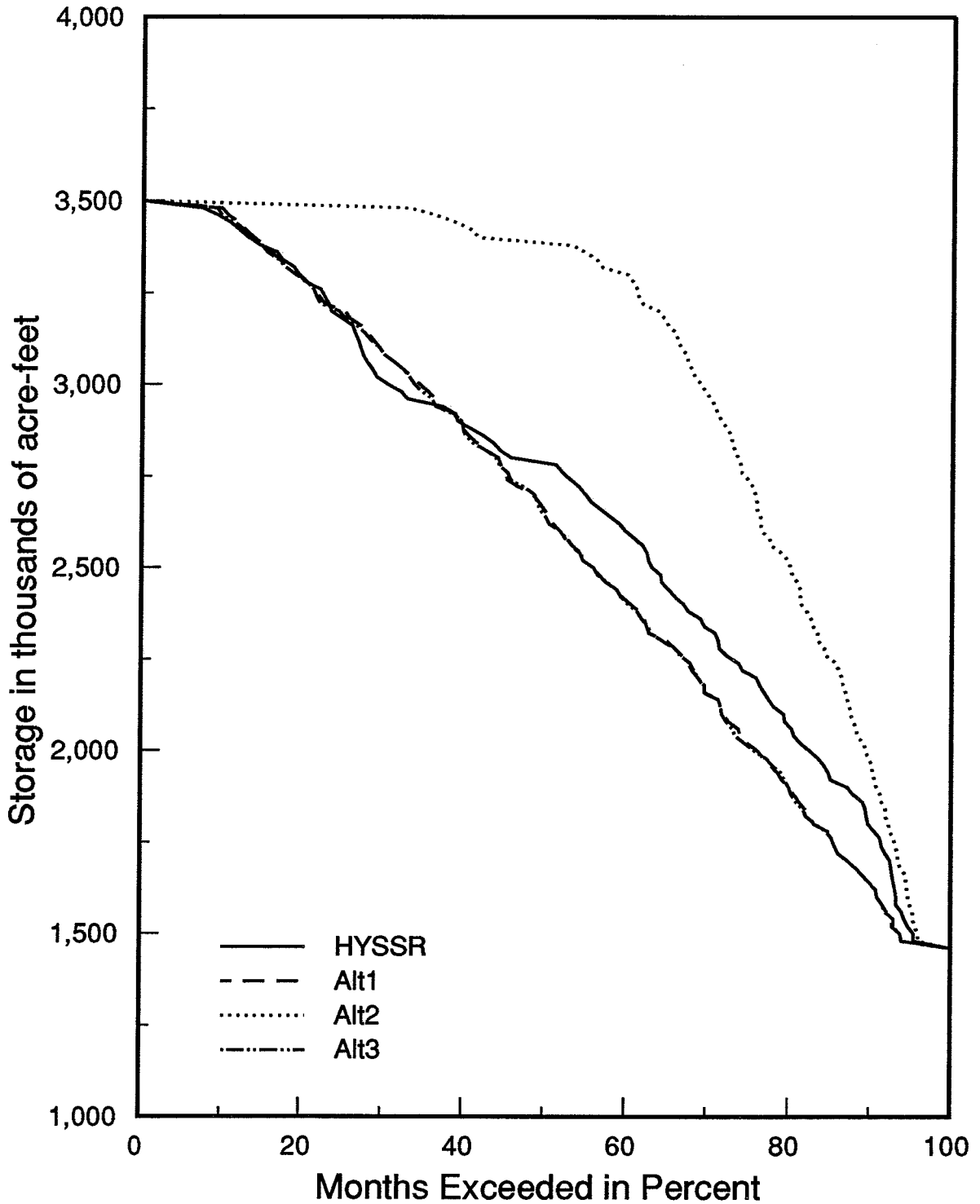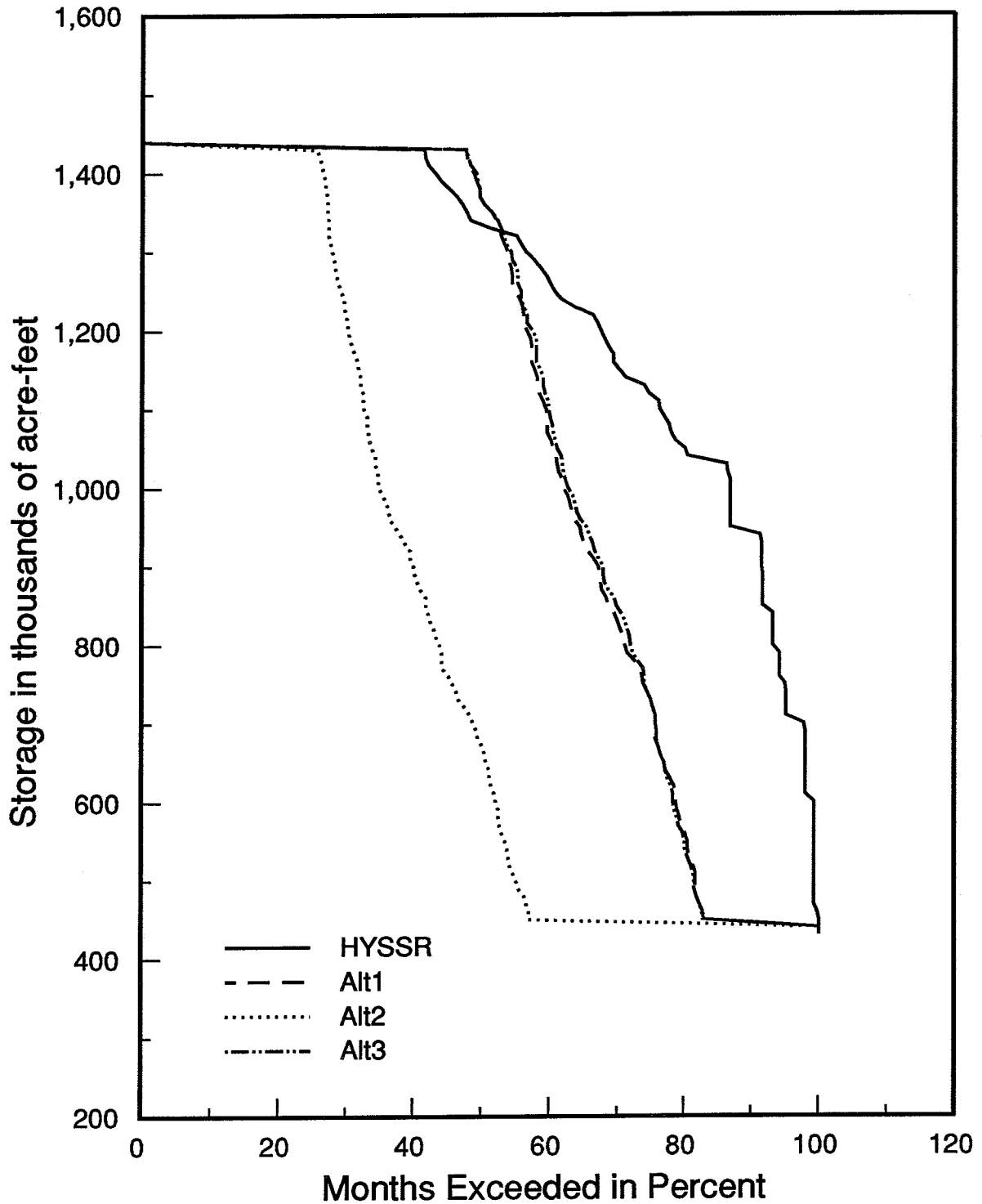For Brownlee, more water tends to be stored by HYSSR than any alternative examined by HEC-PRM. Operation without hydropower penalties (Alternative 2), keeps Brownlee driest of all. Since there are only hydropower penalties at Brownlee, water for flood control is stored anywhere else in the system which has penalties for low storage (such as Dworshak).

All reservoirs in this sub-system are largely unaffected by provision of additional Canadian Treaty storage in Mica, indicating the only localized importance of this potential supplemental storage.

4.7 System Upstream of The Dalles Nodes

The system upstream of The Dalles contains all projects modeled for the HEC-PRM alternatives and HYSSR.

4.7.1 System Operation. Figures 4.10 (*a, b, c*) show the releases prescribed for The Dalles reservoir during the period 1943-1949, with Alternatives 1, 2, and 3, respectively. Figures 4.11 compares the flow frequencies at The Dalles during the April - July fish migration season for the three alternatives and HYSSR results. Appendix F shows time series of storage for Mica, Grand Coulee, and Dworshak and flow at The Dalles for each alternative compared with HYSSR results.

Typically, at The Dalles, Alternative 1 flows have somewhat less seasonal variation than the HYSSR simulation. Alternative 1 late-summer and early-fall releases tend to be greater than for HYSSR. High flows in spring and early summer, common to both HYSSR and Alternative 1, tend to be more consistent for Alternative 1 HEC-PRM operations, with HEC-PRM operation typically having lower peak flows during these periods, as illustrated in Figure 4.11.

Elsewhere in the system, Alternative 1 tends to keep Grand Coulee full more often than HYSSR results, as discussed previously, drawing down Mica earlier in the season for this purpose. Operation of Dworshak reservoir is usually similar for HYSSR and Alternative 1, with perhaps some tendency to draw down a little earlier in the season and typically having a more regular drawdown-refill cycle between years for Alternative 1. Comparisons of operations at all reservoirs were not performed.

Comparing operations under Alternative 2 (no hydropower penalties) to Alternative 1 operations, flows at The Dalles (Figure 4.10) tend to have greater seasonal variation during dry years, with lower flows in fall and greater flows during spring and summer. Flows at The Dalles tend to be somewhat similar during normal years for both Alternatives 1 and 2. Elsewhere in the system, Grand Coulee tends to be drawn down more under Alternative 2 than under Alternative 1, particularly during dry years. Operation of Mica is similar, but occasionally diverges. Operation of the sub-system above Granite is very different between Alternatives 1 and 2, as discussed earlier. Dworshak tends to be kept much fuller and Brownlee tends to be kept much emptier for Alternative 2 operations than for the other alternatives (including HYSSR).
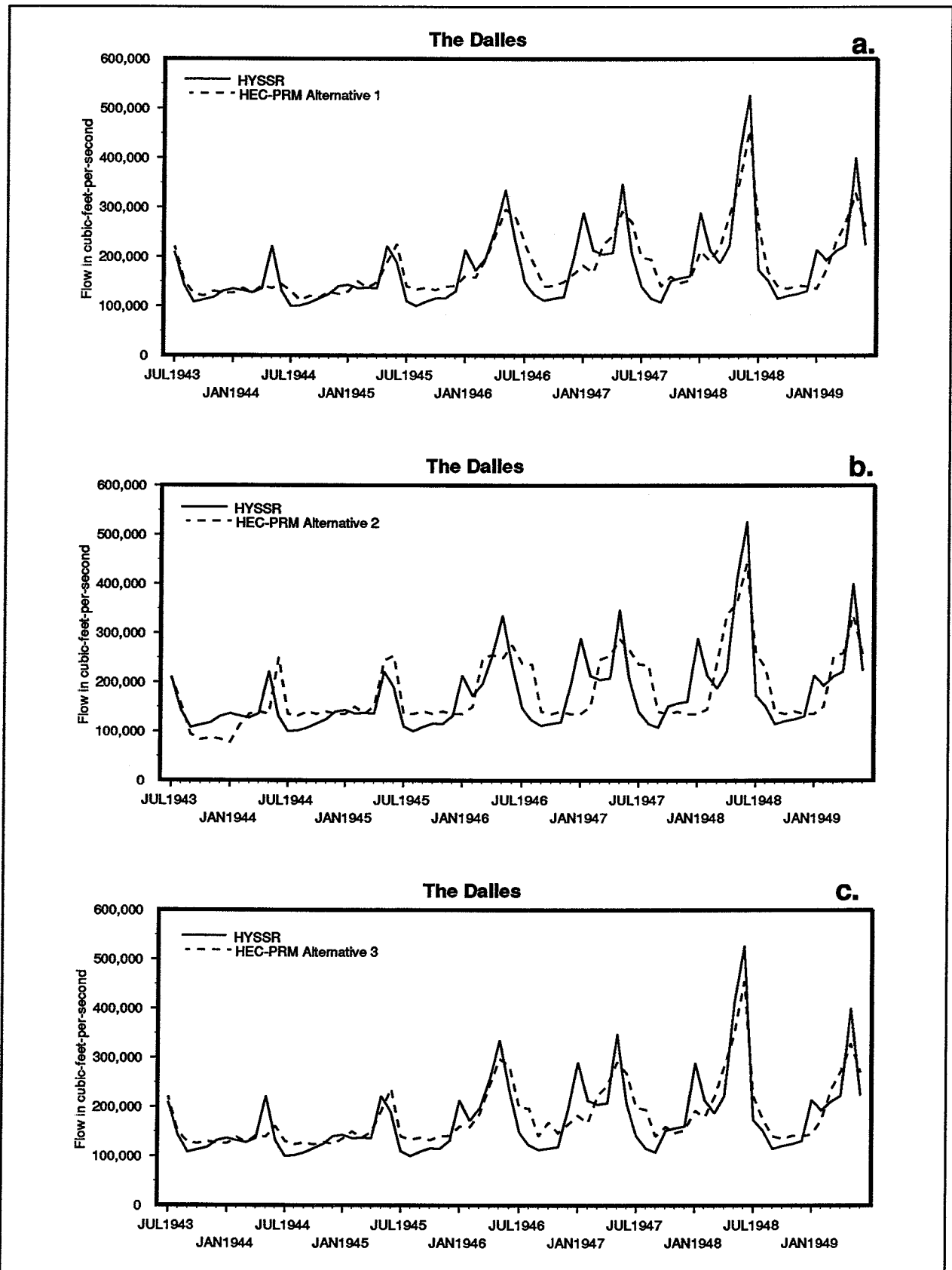
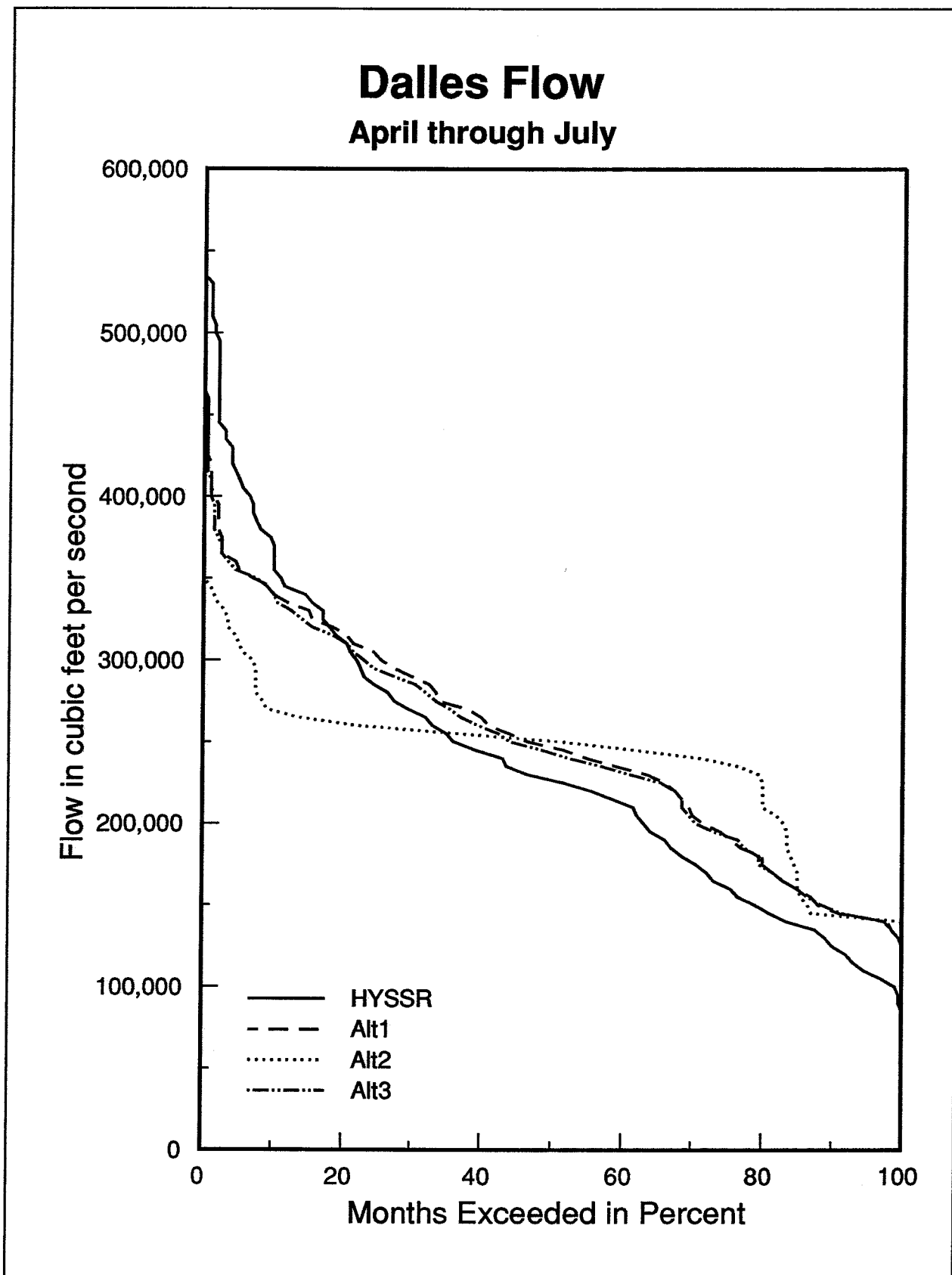**FIGURE 4.10 1943 - 1949 Flow at The Dalles: HYSSR & Alternatives**

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Dalles Flow

April through July

FIGURE 4.11 Exceedance Frequency for The Dalles Flows (April - July)

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Alternative 3 (additional Canadian Treaty storage) operates essentially as Alternative 1 with the exception of a greater tendency to keep Grand Coulee full at the expense of storage in Mica. Operation of reservoirs on the sub-system above Granite is essentially the same for Alternatives 1 and 3. Flows at The Dalles vary insignificantly between these two alternatives.

Overall, June-October releases from The Dalles tend to be greater for all HEC-PRM alternatives than for HYSSR results. Releases in the fall tend to be lower for all HEC-PRM alternatives than for HYSSR, some period of lower flows being needed to conserve mass. All HEC-PRM alternatives also tend to keep Grand Coulee fuller than HYSSR operations, although perhaps this is a result of lack of penalty functions for storage at Mica and Arrow.

4.7.2 System Performance. System-wide performance indices are presented in Table 4.4. Alternative 1 compared to HYSSR operation shows reduced penalties for hydropower and all other purposes. Evidently, operation to achieve the minimum hydropower penalty reflected in HEC-PRM, which dominates HEC-PRM system operation, provides net improvement in operation for the other purposes. Relative improvements, while potentially significant for most purposes, are most dramatic for irrigation and recreation purposes. The reliability, resiliency, and vulnerability indices also indicate improvements in operation for all purposes.

Alternative 2 (operation without hydropower penalties) increases total penalties (with hydropower penalties assessed in the post-processing) by $7,870 million over the 50-year run compared with Alternative 1, averaging about $157.4 million per year of additional penalty. Comparing results from Alternatives 1 and 2 for the 50-year period, hydropower penalties are $8,904 million greater for Alternative 2, a 7.5% increase from Alternative 1 hydropower penalties. However, the sum of other penalties is $1,034 million less. Most of this improvement in non-hydropower penalties is from flood control ($612 million or a 23% reduction), but substantial penalty reductions also occur for fish protection ($376 million or a 43% reduction), navigation ($64 million or an 85% reduction), and recreation ($7.4 million or a 15% reduction). Irrigation penalties, paradoxically, increased when hydropower penalties were removed, increasing $26 million or 40% from Alternative 1 results. This is likely due to lessened storage, and therefore greater pumping heads for pumped irrigation withdrawals from Grand Coulee under Alternative 2. (Irrigation penalties are incurred only at Grand Coulee, Granite, McNary, and John Day storage nodes.)

Penalties and performance indices for Alternatives 1 and 3 (with additional Canadian Treaty storage) are essentially the same. The addition of 5 million ac. ft. of storage in Mica decreases total penalty by only $422 million over the 50-year run period or $8.44 million/year on average. This implies an average value for storage at Mica of about $1.68/year per acre-ft of addition storage capacity. There is likely to be considerable uncertainty in this small figure given the uncertainty in existing penalty functions and the absence of economic penalty functions for Mica and Arrow reservoirs. Still, the actual value of additional Mica storage is likely to be small. The greatest benefits of increased storage capacity at Mica appear to be for hydropower ($381 million over 50 years or a 0.3% penalty decrease) and irrigation ($11 million or a 17% decrease) resulting from keeping more water in Grand Coulee. Hydropower resiliency is increased somewhat by the additional Mica storage, from 35.7% to 42.2%. Otherwise, there is little significant performance difference between Alternatives 1 and 3.

TABLE 4.4

Comparison of Performance: System Upstream of The Dalles Node (inclusive)

Performance index (1)	HYSSR Operation (2)	Alternative 1 (3)	Alternative 2 (4)	Alternative 3 (5)
Penalty, in $ millions for (50-year period)				
Total	133,720.0	122,277.0	130,146.7	121,855.0
Hydropower	128,450.0	118,536.7	127,440.6[1]	118,156.0
Flood control	3,474.0	2,670.5	2,058.3	2,634.2
Fish protection	1,043.9	875.4	499.5	884.0
Navigation	100.0	76.0	11.5	75.7
Irrigation	507.8	66.0	92.1	55.1
Recreation	140.0	48.1	40.5	46.3
Reliability, in %				
Hydropower	62.0	79.5	70.2	81.8
Flood control	79.8	81.5	82.5	81.1
Fish protection	77.9	80.2	83.0	79.9
Navigation	90.8	90.8	97.9	90.8
Irrigation	87.0	89.2	89.1	89.4
Recreation	23.1	44.7	54.9	44.9
Resiliency, in %				
Hydropower	28.9	35.7	40.7	42.2
Flood control	22.7	22.5	24.4	21.4
Fish protection	45.3	49.0	59.3	49.4
Navigation	38.0	44.6	80.0	44.1
Irrigation	30.0	33.4	44.5	35.7
Recreation	5.6	19.0	22.9	18.7
Vulnerability				
Hydropower, MW	761.8	1,098.1	1,628.0	1,130.5
Flood control, kaf	2,022.2	2,096.4	2,436.0	2,041.1
Fish protection, kaf	3,301.0	2,960.9	2,478.7	2,951.1
Navigation, kaf	498.2	427.1	289.8	430.4
Irrigation, kaf	2,152.8	1,567.5	1,753.7	1,499.5
Recreation, kaf	1,177.2	1,147.5	1,608.5	1,120.6

[1] Hydropower penalty computed via post-processing based on HEC-PRM results without hydropower objective and hydropower penalty functions.

Results shown on Table 4.5 indicate that HYSSR and the three alternative operation plans for a period-of-record analysis (1928 - 1978) would generate 22 - 27 percent more average annual energy than the specified average annual energy load. Each would also just meet the average annual energy load during the critical period (1928 - 1932). Despite this, on a monthly basis, all alternatives fail to meet monthly power demands during the critical period. Each of the three alternatives shown on Table 4.4 have somewhat greater hydropower reliability and resiliency, and lesser penalties, compared with HYSSR results, but may be significantly more "vulnerable," having greater average deviations from hydropower targets.

TABLE 4.5
Comparison of Average Annual Hydropower Generation:
System Upstream of The Dalles Node (inclusive)[1] (Megawatt-energy x 10^5)

Performance Period	System Load (Demand)	HYSSR Operation	Alternative 1	Alternative 2	Alternative 3
Critical Period (1928 - 1932)	1.41	1.42	1.45	1.44	1.46
% Months Failing to Meet System Load		86%	64%	62%	57%
Adopted Analysis Period (1928 - 1978)	1.40	1.71	1.78	1.76	1.79
% Months Failing to Meet System Load		38%	20%	30%	18%

[1] Table developed from computed monthly average energy values from HYSSR and HEC-PRM results for the period-of-record (1928 - 1978).

Alternative 1 hydropower results are significantly more reliable, somewhat more resilient, and significantly less vulnerable than those of Alternative 2. Comparing HYSSR hydropower production to that from Alternative 2, Figure G.1 (*b*) of Appendix G, clearly shows that HEC-PRM Alternative 2 (without the hydropower objective) during the critical period (1928 - 1932) yields significantly greater fluctuations in hydropower generation than either HYSSR operations or HEC-PRM operation for Alternatives 1 and 3. While, Alternative 2 average annual production may exceed average annual power demand, the monthly distribution of this generation is less reliable. This is the result of considerable incidental hydropower production from the Alternative 2 operation. Despite being devoid of hydropower penalties, for the analysis period, HEC-PRM operation for Alternative 2 yields 99.88% of the average annual hydropower production of Alternative 1 and 7.5% greater

hydropower penalty. During the critical period (1928 - 1932) Alternative 2 hydropower production is 99.31% of the average annual hydropower production of Alternative 1, with comparable hydropower reliability.

4.8 Summary and Discussion of Results

4.8.1 Summary of Results. Each of the three alternatives provides apparent improvement over present system operation based on performance criteria previously described. This is likely somewhat spurious because of the difference in reflecting seasonal hydropower demands as previously discussed. The average annual energy is essentially the same as present operation for all alternatives. This indicates a small amount of spillage throughout the system. The average annual energy produced exceeds the demand for the 50-year period and just meets the demand for the critical period (1928 - 1932). Additional analyses are required to determine how the alternatives meet the demand on a seasonal or monthly basis. The lack of significant seasonal variations in the hydropower penalty functions may have produced unrealistic results. It may also explain the greater vulnerability of the alternatives than the present operation which is based on HYSSR data.

Alternative 3, the use of an additional 5 million acre-feet of Mica storage, causes an expected, significantly different operation at Mica than Alternative 1 which optimizes for present conditions. This results in more stable operation of Grand Coulee pool levels (from visual inspection of the time-series plots) but little effect downstream at The Dalles or in other sub-systems (e.g., above Granite). Operation of Dworshak on the Snake River is essentially the same for Alternatives 1 and 3. The performance indices shown on Tables 4.2, 4.3, and 4.4 also show little advantage from additional Mica storage.

Alternative 2, which omits the hydropower objective, clearly shows enhanced reliability and resiliency for system navigation, recreation, and fish protection (see Table 4.4). It is also significantly less vulnerable for fish protection and navigation, although it is significantly more vulnerable for hydropower, flood control and recreation. Additional study of seasonal effects of this alternative on the fishery and more detailed assessments of the impact on seasonal, monthly and daily hydropower requirements seem warranted. The major operational differences for Alternative 2 operations, compared with Alternative 1, are greater seasonal variation in system outflows during dry years, less Grand Coulee storage, and very different operation of the sub-system above Granite, perhaps because Brownlee has only hydropower penalties and the elimination of these penalties increases the relative importance of maintaining storage at Dworshak, making Brownlee function primarily for maintaining flows and storage levels downstream.

4.8.2 Discussion of Results. The HEC-PRM results presented in this chapter illustrate the ability of HEC-PRM to provide information for reasonable operating and performance comparisons of system planning alternatives.

The utility of these particular results is qualified due to some particular shortcomings in this particular HEC-PRM model of the Columbia River System. These shortcomings are primarily the absence of seasonally varying hydropower penalties and the absence of a complete set of penalty functions for some reservoirs in the system, notably at Mica, Arrow, and Brownlee.

In addition, HEC-PRM results have inherent shortcomings due to the perfect foresight embedded in the HEC-PRM solution algorithms. HEC-PRM can see far into the future to either gradually create large amounts of storage for flood management or store additional amounts of water for droughts far in advance of when real system operators could be expected to take such actions. This makes direct comparison of HEC-PRM results with HYSSR results, for instance, a bit unfair in such cases.

Nevertheless, HEC-PRM results for this system appear to be reasonable and offer economically-supported insight into optimal system operation under a wide variety of conditions. Such results might be useful in themselves for preliminary performance and operational comparison of planning alternatives. This was the use of HEC-PRM here, where current operational objectives and conditions were compared with those given additional Canadian Treaty storage (Alternative 3) and with elimination of hydropower as an operating objective (Alternative 2).

From the results presented in this chapter, additional Canadian Treaty storage in Mica reservoir (Alternative 3) would not seem to have great value to the system in most cases. HEC-PRM results could be examined in more detail to identify in which years additional Mica storage would have had particular value. If additional Mica storage were found to be particularly valuable under certain conditions, such specific results might provide the basis for contingent storage contracts with Canadian authorities to provide additional storage in particular types of years under specific conditions.

The results following elimination of hydropower penalties from the system (Alternative 2) illustrate the very large incidental hydropower provided by the system and the potentially different operation of the system for non-hydropower objectives during dry years. The results for this particular alternative might be particularly sensitive to the absence of full sets of non-hydropower penalty functions for some parts of the system (e.g., Brownlee).

Another use of HEC-PRM results, for promising alternatives, is as a basis for operating rule development. This approach has been taken for the Missouri River system (USACE, 1992b) and can provide detailed and specific suggestions for improvement of system operating strategies and operating rules. There may also be some potential for the use of HEC-PRM results for shorter periods, ranging from seasonal or annual operation to operation planning over a few years time horizon. The California Department of Water Resources uses a somewhat similar approach with great success for its near-term operational planning (Chung, et al., 1989). Some conclusions and recommendations from this work are provided in the final chapter.

Chapter 5

Conclusions and Recommendations

5.1 Conclusions

5.1.1 The HEC-PRM system analysis model has been successfully modified and improved for application to the Columbia River System. The model runs on a PC. A data set representing the physical system, hydrologic analysis period, and operation purposes and their economic values was prepared and incorporated into the model.

5.1.2 The HEC-PRM model can be used to evaluate and compare planning and operational alternatives. The model was executed for several alternatives specified by NPD. Several indices of performance were used to compare these alternative operations with operation following current procedures represented by HYSSR results. As discussed in Chapter 4, the HEC-PRM results clearly show differences in economic value (penalties), reliability, resiliency, and vulnerability for the alternatives specified. Differences in broad system operation strategies are also evident between each alternative and can be quickly identified by HEC-PRM. The three alternatives analyzed in this study were HEC-PRM operations for 1) current system capacities and objectives, 2) current system capacities and objectives, but with hydropower objectives excluded, and 3) current system capacities and objectives, but with additional Canadian Treaty storage at Mica reservoir.

5.1.3 Providing more Canadian Treaty storage at Mica does not significantly improve system performance. Alternative 3 in this study allowed access to an additional 5 million ac. ft. of storage in Mica reservoir, should that storage be useful for operation. Based on the penalties and indices computed, that storage does not significantly improve performance. Additional Mica storage would be valued at an average of about $1.68/ac. ft.-year.

5.1.4 Omitting the hydropower objective enhances system fish protection, navigation, and recreation, at the expense of system power. Alternative 2 omitted hydropower penalties from Alternative 1. The analysis shows that fish protection, navigation, and recreation benefit significantly from omitting the hydropower objective. While average annual energy generation is not dramatically reduced, the system hydropower penalty is significantly increased. No conclusions are made concerning seasonal and monthly demands. The hydropower penalty functions used in this study included seasonal variation in capacity only; energy values were not varied through the year and so did not completely reflect system demands. This alternative showed the greatest operational variation of the three alternatives, with dramatically different operation of the sub-system above Lower Granite. This change in operations may be due to the lack of non-hydropower penalties at Brownlee.

5.1.5 There are several potential uses for an HEC-PRM model of the Columbia River System. This study has shown the utility of the HEC-PRM model of the Columbia

River System for preliminary comparison of the operation and performance of planning alternatives (such as adding Canadian Treaty storage or eliminating hydropower operating criteria). A prescriptive model, such as HEC-PRM may also have use for the development of long-term system operating strategies and the development of annual or seasonal operating plans and rules. This has been accomplished using the HEC-PRM results of the Missouri River system (USACE, 1992b).

5.1.6 Some refinements to the HEC-PRM model are probably desirable to improve representation of the systems economic penalties. The absence of a full set of penalty functions at Brownlee, Mica, Arrow, and some other nodes may have a significant effect on HEC-PRM prescribed operations. This is evident for Alternative 2 operation of Brownlee reservoir, mentioned above. An optimization model is only as useful as its penalty functions are representative. Suggestions are also made for improving hydropower penalties.

5.1.7 HEC-PRM relies on penalty functions to represent system-operation goals and priorities. To realistically reflect physical and inherent practical aspects of operation of the system, penalty functions must be constructed with great care. In addition to representing purely economic values, penalty functions must also reflect the capabilities and limitations of the system's physical infrastructure. Thus, the break-points and other characteristics which shape penalty functions should reflect such factors as channel, turbine, and outlet capacities, the use of minimum streamflows to maintain habitat during non-recreation seasons, and practical aspects of desired flow regimes. These issues are discussed further in the IWR report (USACE, 1993).

5.2 Recommendations

5.2.1 The results from the three alternatives presented and briefly evaluated here should be examined in more detail. The complete model and output are contained in floppy disk files accompanying this report. The output for each alternative includes releases, storages, penalties for each objective, total penalties, and energy generation for each month of the period-of-record at each node in the system. Additional insight into system operation and performance under the alternatives might be found from more detailed examination of these data. For example, the penalty tabulations reflect economic cost and can be used to compare the economic impact of operation alternatives. To illustrate from Table 4.4, the hydropower penalty increases from 118,536,000 for Alternative 1 to 127,440,000 for Alternative 2. The penalty units are thousands of dollars; thus, the approximate loss in hydropower benefits as reflected by the hydropower penalty functions is $178 million per year. This is computed as: (127,440,000 - 118,536,000)/50 X $1,000 = $178,000,000. The penalty values for the other purposes are also economically based permitting similar calculations of economic impacts of different operation plans. Statistical analysis of reservoir pool levels, releases, and correlation studies might provide useful insights into system performance and operation.

5.2.2 Hydropower penalty functions should be refined. The hydropower penalty functions should be modified to include seasonal variation in energy value, similar to the manner in which hydropower capacity benefits were shaped to seasonal demands for penalty

function development. Since hydropower is the dominant purpose driving existing operations, incorporating seasonal value for hydropower would permit more realistic and meaningful analysis of economically based system operation. Trade-off analysis between operation purposes might thus be more exact.

5.2.3 Additional alternative operation strategies can be examined. Additional specific planning alternatives could be formulated and analyzed with HEC-PRM. Additional alternatives might be based on findings from the three alternatives studied here or those suggested by on-going SOR investigations.

5.2.4 Operating strategies and rules should be derived from HEC-PRM results for the Columbia River System. Detailed application of HEC-PRM for reservoir operations requires additional work to develop reservoir operating strategies and rules from HEC-PRM results. Such work has been accomplished for the Missouri River system (USACE, 1992b) and is currently being extended and tested. Attempts should be made to derive system and project operation rules consistent with common operation methods, based on prescribed HEC-PRM operation. These rules would then be tested with HYSSR to determine their practical value and to provide refinement for possible implementation or incorporation into existing operation policies.

5.2.5 Extensive use of the Columbia River System's HEC-PRM model should be accompanied by additional technical improvements to the model. Should extensive use of HEC-PRM be contemplated for SOR or future study of the Columbia River System, a number of technical improvements in the model are desirable. These improvements include: additional penalty functions at several locations and updated depletions, and possible refinement of hydropower representations to include system-wide power demands.

Appendix A

What is HEC-PRM?

APPENDIX A

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Appendix A

What is HEC-PRM?

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Appendix A

What is HEC-PRM?

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Appendix A

What is HEC-PRM?

A.1 Summary

HEC-PRM is a reservoir system operation analysis model developed by HEC. As its name implies, HEC-PRM *prescribes* reservoir-system operation to achieve user-defined goals. To find this operation, the model.

- Represents reservoir operation as a problem of water allocation over time. It formulates this allocation problem as a mathematical-programming problem with flow, release, and storage as decision variables.

- Represents goals of operation in the mathematical-programming formulation with penalties related to flow, release, and storage and with upper and lower bounds on flow, release, and storage.

- Solves the mathematical-programming problem with a specialized linear-programming (LP) algorithm (network flow programming).

- Processes the algorithm's results to define the prescribed system operation in convenient terms.

Software to implement HEC-PRM is generalized: system configuration and operation goals are defined through user input. This permits analysis of practically any existing or proposed reservoir system. The software incorporates the HEC Data Storage System (HEC-DSS) and associated utilities to manage and display data and results.

A.2 HEC-PRM Generates and Compares Operation Alternatives

Decisions regarding reservoir operation typically are made by nominating a set of alternative operation schemes, evaluating the efficiency of each scheme in terms of identified goals, and picking the candidate scheme that is "best". This can be accomplished with a descriptive or a prescriptive mathematical tool.

The U.S. Army Corps of Engineers (USACE) traditionally has used descriptive tools to answer the question "How would the reservoir system perform if we follow specified operating rules?" A descriptive tool provides the answer by simulating mathematically all critical physical processes. Computer program HEC-5 (USACE, 1982a) is an example of a descriptive model. In application for analysis of performance, this program evaluates the system-wide impact of following operation rules (specified in terms of desired storage levels) by simulating reservoir mass continuity, channel mass continuity, and hydropower production.

With this accounting, the user can assess, formally or informally, the efficiency of alternative rules. To identify "best" rules, the user iteratively nominates, simulates, and compares alternatives.

A prescriptive tool turns the question around and asks "Which operating rules should we follow to optimize system performance, given a formal definition of goals of and constraints on operation?" To answer this question, a prescriptive tool:

- Systematically *generates* a candidate operating scheme for the system;

- Simulates the system's response to the scheme, using an embedded simulation model;

- Evaluates, with the results of the simulation, the feasibility and efficiency of the scheme, using a *formal* statement of operation goals and objectives;

- Iterates until *all* (or a reasonably large set of) alternatives have been generated, simulated, and evaluated;

- Identifies the best scheme from those evaluated.

HEC-PRM is such a prescriptive tool. It incorporates a linear simulation model, represents operation goals with constraints or penalties on flow, release, or storage, and uses a specialized LP algorithm to find the optimal allocation of water to meet system demands.

A.3 HEC-PRM Includes a Simulation Model

A key component of any prescriptive tool is the simulation model it incorporates. The simulation model in HEC-PRM represents a reservoir system as a network, a collection of nodes interconnected by arcs. Reservoirs and system demand and supply points are represented as nodes. Conveyance and storage facilities are represented as arcs. This network representation of the reservoir-system operation problem is similar to that used by Sigvaldason (1976), Martin (1982), Ikura and Gross (1984), Sabet, et al. (1985), and Chung, et al.(1989).

Critical physical processes modeled with the network representation include reservoir mass continuity and channel mass continuity.

A.3.1 Reservoir Mass Continuity. The HEC-PRM simulation model includes the following form of the reservoir mass continuity equation:

$$SB_t + I_t = R_t + W_t + SE_t + EVAPO_t \tag{1}$$

in which SB_t = beginning-of-period-t storage; I_t = period-t total inflow; R_t = period-t release; W_t = period-t reservoir withdrawal; SE_t = end-of-period-t storage; and $EVAPO_t$ = net reservoir

evaporation in period t. This evaporation is a function of average reservoir surface area, which, in turn is a function of storage. Within typical reservoir operating ranges, the resulting function is approximately linear. Thus, HEC-PRM estimates the evaporation as

$$EVAPO_t = EV_t (SB_t + SE_t) / 2 \qquad (2)$$

in which EV_t = evaporation per unit storage, period t. Combining Equations 1 and 2 yields

$$SB_t + I_t = R_t + W_t + SE_t + EV_t (SB_t + SE_t) / 2 \qquad (3)$$

R_t, W_t, and SE_t are the decision variables; they are to be prescribed to meet operation goals.

Equation 1 can be represented with a simple network, as shown in Figure A.1. The node represents the reservoir in period t. Mass is conserved at the node. Flows on the arcs represent the inflow, storage, withdrawal, evaporation, and release. The flows on the beginning-of-period storage and inflow arcs are known. The flows representing release, withdrawal, and end-of-period storage are to be prescribed. Flow on the evaporation arc is computed as a function of the average storage; the end-of-period storage decision will have a direct impact on this value.
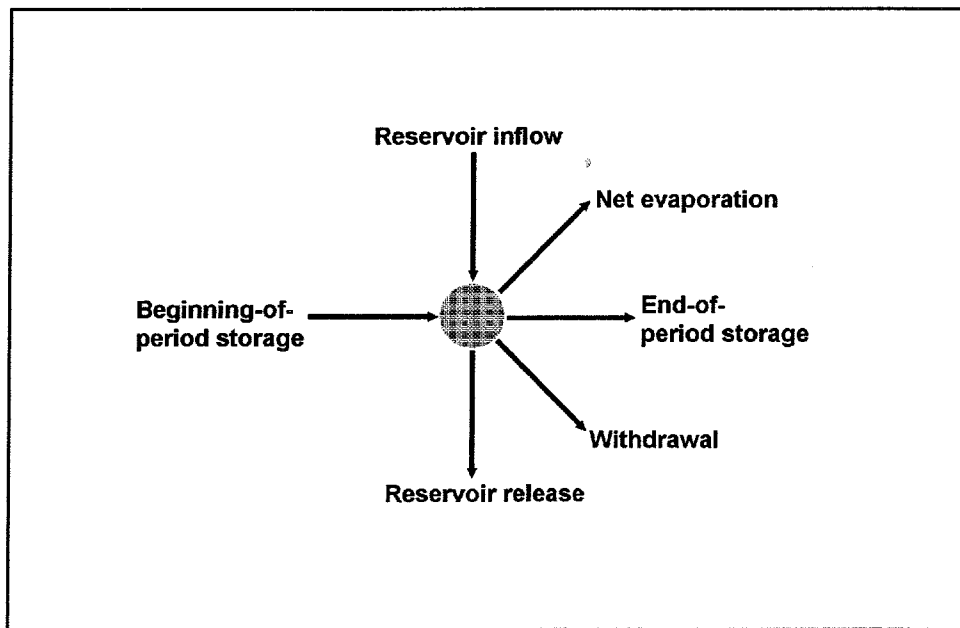
FIGURE A.1 Single-period Reservoir Mass Continuity Representation

To represent multiple-period operation, a reservoir mass continuity equation is defined for each period. In that case, SB_t, the beginning-of-period-t storage, equals SE_{t-1}, the end-of-period-t-1 storage. This can be represented with a network, as shown in Figure A.2. The beginning-of-analysis storage and all inflows are specified; other storages, withdrawals, and releases are to be prescribed. Evaporation is computed as a function of storage.

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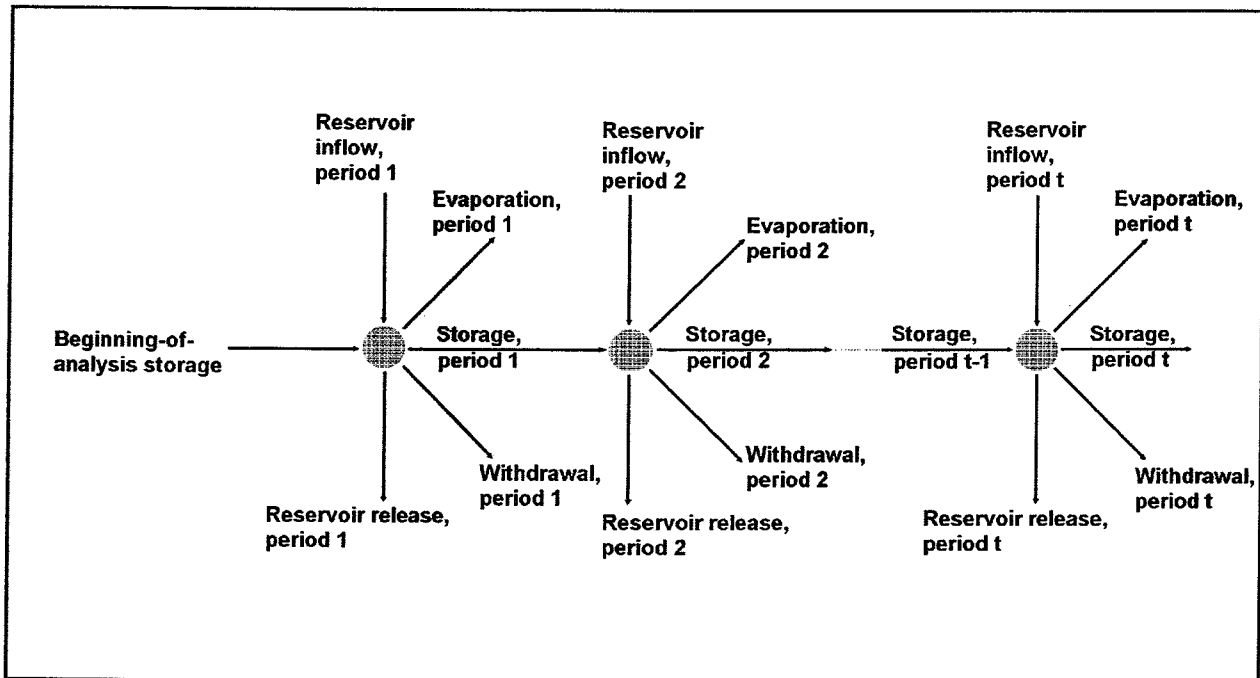
FIGURE A.2 Multiple-period Reservoir Mass Continuity Representation

A.3.2 Channel Mass Continuity. In the HEC-PRM simulation model, each system channel reach is represented by an arc that begins and ends at a node representing a reservoir or system control point. Flow may be added to and/or diverted from the reach at any control point, but flow is conserved in all reaches. This is described mathematically as follows:

$$Qu_t + LI_t = D_t + Qd_t \tag{4}$$

in which Qu_t = period-t flow in channel upstream of control point; LI_t = period-t local inflow to channel; D_t = period-t diversion at control point; Qd_t = period-t flow in channel downstream of control point. In this equation, LI_t is known, and all other variables are to be prescribed by the model. This relationship also can be represented with a network, as shown in Figure A.3. The node represents the control point, and the arcs represent flow. Flow is conserved at the node.

To represent a complex channel system, a channel mass continuity equation is defined for each control point. In that case, as illustrated in Figure A.4, the flow downstream of one control point is the flow upstream of the next control point.

By combining reservoir and channel continuity equations, any system can be modeled. For example, a single-period model of a reservoir upstream of two series control points includes one reservoir continuity and two channel continuity equations. For the control point immediately downstream of the reservoir, the upstream flow equals the reservoir release. For the second control point, the upstream flow equals the first control point's downstream flow. This is represented with the network shown in Figure A.5.
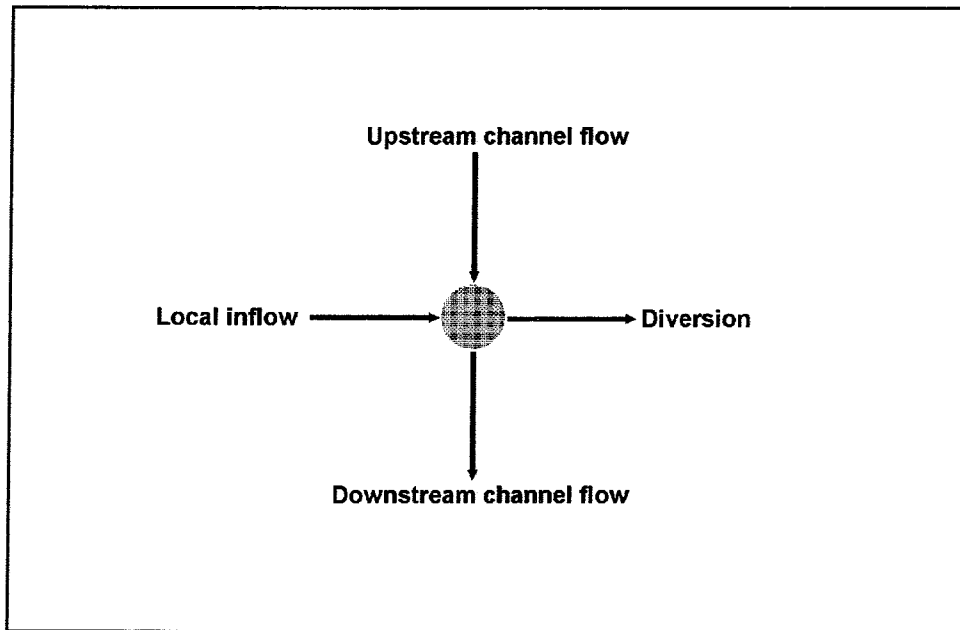
FIGURE A.3 Single Control-point Channel Mass Continuity Representation
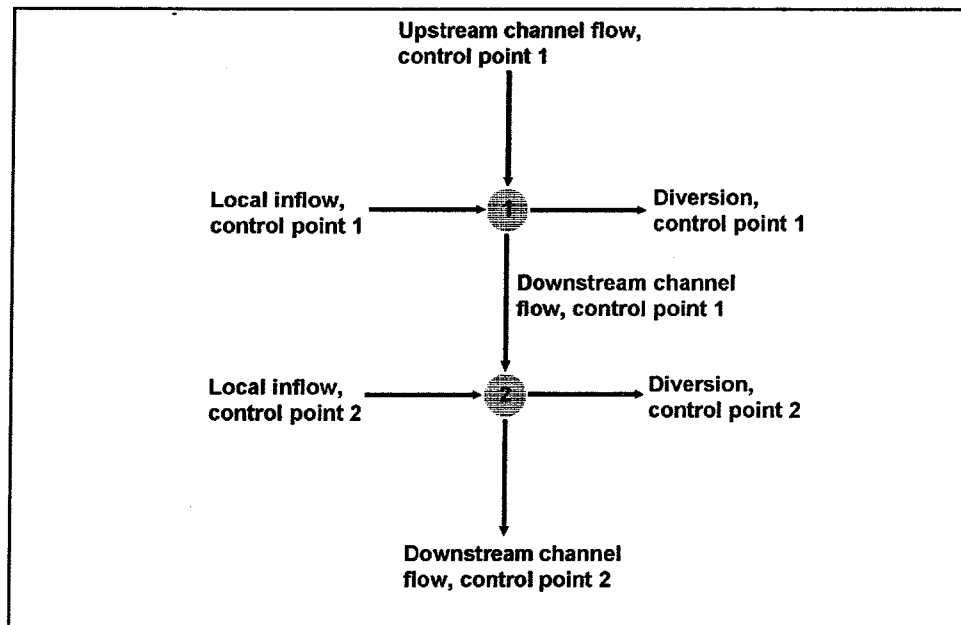
FIGURE A.4 Multiple Control-point Channel Mass Continuity Representation

APPENDIX A
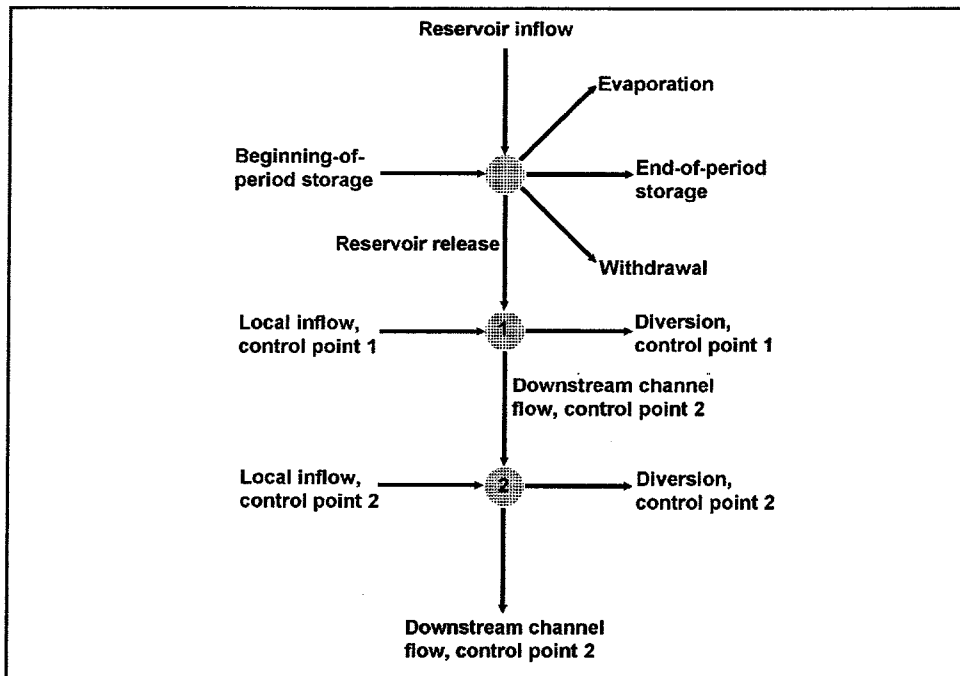
FIGURE A.5 Reservoir System Representation for Single Period

The representation is extended over time by joining single-period models with arcs which represent storage, as illustrated in Figure A.6.
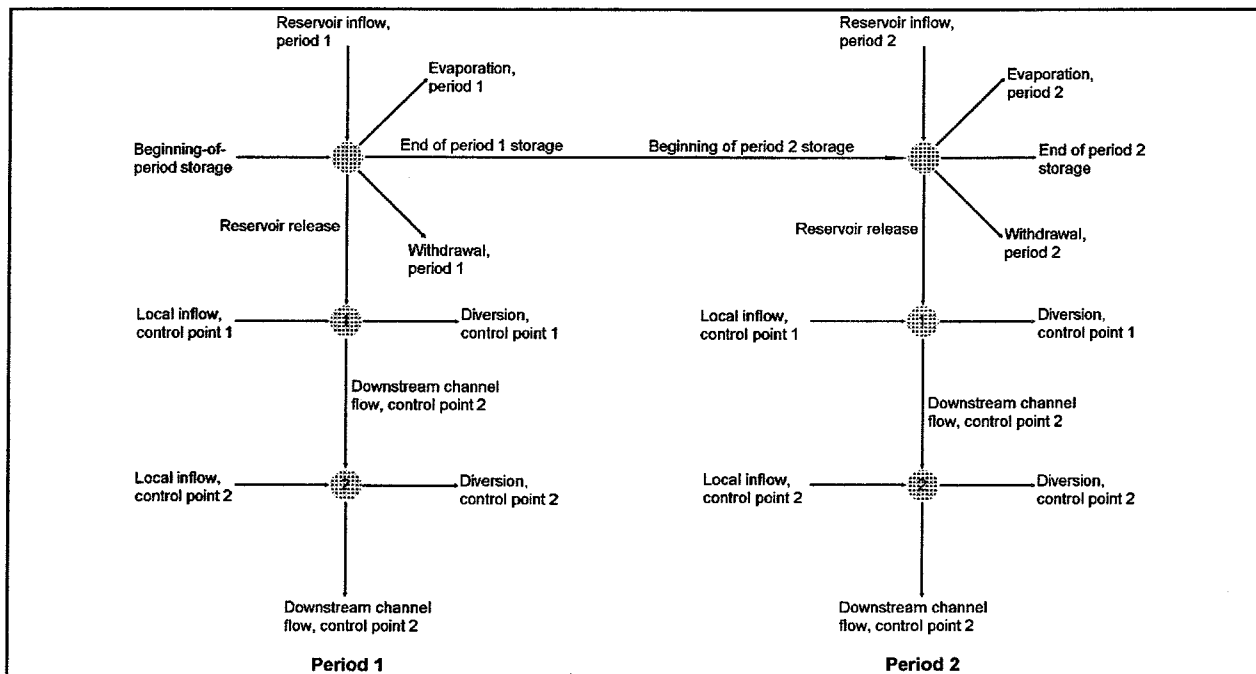
FIGURE A.6 Reservoir System Representation for Multiple Periods

A.4 HEC-PRM Represents Operation Goals with Constraints and Penalty Functions

No unique solution exists for the mass continuity equations of the embedded simulation model. For example, if the initial storage is 15 kaf and inflow is 2 kaf in the reservoir represented by Figure A.1, any combination of end-of-period storage, evaporation, and release that total 17 kaf will satisfy the reservoir mass continuity equation. A similar situation exists at the downstream control points.

Central to the HEC-PRM formulation is the idea that, in terms of meeting operation goals, the quality and feasibility of an operating scheme can be represented formally in terms of the magnitudes of the decision variables. With HEC-PRM, this is accomplished by imposing constraints on flow, release, or storage, and by assigning penalties for too much or too little flow, release, or storage.

A.4.1 Constraints on flow, release, or storage. With HEC-PRM, constraints may define an inviolable upper and lower bound on flow, release, or storage at any location any time. No operation scheme that fails to satisfy all such constraints is acceptable. If no such scheme can be found, the operation problem, as stated, is insoluble. For example, if the capacity of the reservoir illustrated in Figure A.5 is 15 kaf, SE_t in Equation 1 must be less than or equal 15 kaf for all t. An operation scheme that yields any SE_t greater than 15 kaf is unacceptable, regardless of how desirable that scheme is otherwise.

A.4.2 Functions that define penalties for too much or too little flow, release, or storage. Functions that define formally the relative value (or lack of value) associated with too much or too little flow, release, or storage permit comparison of alternative operation schemes. For example, if the penalty for release in Figure A.1 is 100 units per kaf, and the penalty for storage is 0.01 unit per kaf, the better operation is to release only water in excess of capacity, as that operation will minimize total penalty.

The penalty functions used with HEC-PRM can be of two types: cost-based or non-cost-based. The cost-based functions show the loss in economic value as flow, release, or storage deviates from the optimum flow (USACE, 1990c). Cost-based penalty functions are typical for urban and agricultural flooding, water supply, recreation, hydropower, and navigation. Non-cost-based penalty functions represent goals of system operation that cannot be quantified in economic terms. For example, a flow requirement for fish and wildlife protection may be represented with a function in which the penalty for low flow arbitrarily is set to force the desired operation. As with the cost-based functions, these functions relate penalty to either reservoir release, reservoir storage, or channel flow at downstream locations. A desirable goal is to develop cost (economic) based penalty functions when possible. This permits unambiguous comparison of alternative and valuing of performance

For analysis of system operation with HEC-PRM, penalty functions for individual purposes at various locations over time are summed. If non-cost based functions are believed to be in units commensurate with the cost-based functions, they are included in the sum. Once the appropriate penalty functions are combined, the result is approximated as a linear

APPENDIX A

function. If the function cannot be approximated well with a single linear segment, a convex piecewise-linear approximation is used instead. Figure A.7 illustrates such an approximation.
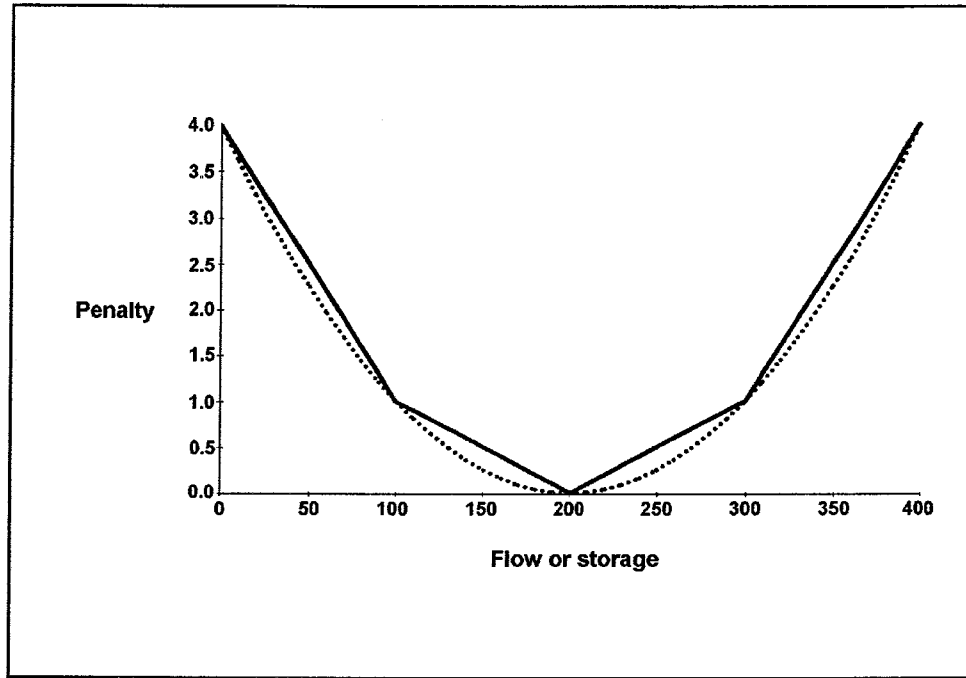
FIGURE A.7 Convex Piecewise-linear Approximation of Penalty Function

A.5 HEC-PRM Uses a Specialized Linear-programming Algorithm

A.5.1 Mathematical Programming Formulation. When the embedded simulation model, constraints, and penalty function are combined, the result is a mathematical-programming model. With substitution of variables to represent flow on the various arcs, the equations of the model can be re-written as:

$$\text{Minimize: } z = \sum_{k}^{m} h_k f_k \tag{5}$$

subject to

$$\sum_{k \in M_O} f_k - \sum_{k \in M_T} a_k f_k = 0 \text{ (for each of the } n \text{ nodes)} \tag{6}$$

$$l_k \le f_k \le u_k \text{ (for each of the } m \text{ arcs)} \tag{7}$$

in which z = the total-system penalty; m = number of arcs; n = number of nodes; k = an index of the arcs; f_k = flow on arc k; h_k, l_k, u_k, a_k = unit cost, lower bound, upper bound, and multiplier for flow on arc k, respectively; M_O = the set of all arcs originating at a node; M_T = the set of all arcs terminating at a node. Solution of this mathematical-programming problem will yield the best allocation of water within the system, given the unit costs, bounds, and multipliers.

A.5.2 Solution of the Linear Problem. As noted earlier, the operation problem defined with Equation 6, the mass continuity equation, cannot be solved as a problem of simultaneous linear equations. The model has more unknowns than equations ($m > n$), so it has an infinite number of solutions. But because these equations and the function to compute total penalty are linear, the simplex LP algorithm will lead to the optimal solution. That algorithm iteratively sets all excess unknowns ($m - n$) to either their upper or lower bounds, leaving a set of n simultaneous linear equations in n unknowns. This set of equations is solved, and the total penalty is computed with Equation 5. This is repeated until all possible solutions are evaluated explicitly or eliminated implicitly. Because of the characteristics of Equations 5, 6, and 7, HEC-PRM is able to employ a specialized form of this simplex algorithm, a network-flow algorithm.

A.5.3 Solution of the Nonlinear Problem. Determining the optimal water allocation in systems with hydropower requires a slight modification to the solution procedure. Hydroelectric energy is not a simple linear function of flow or storage, so the hydropower penalty functions are not simple linear equations (see Appendix B). Instead they are functions of flow and head (which is related to storage). Figure A.8 is an example of such a function. Each of the relationships in this figure defines penalty as a function of release for a given storage.
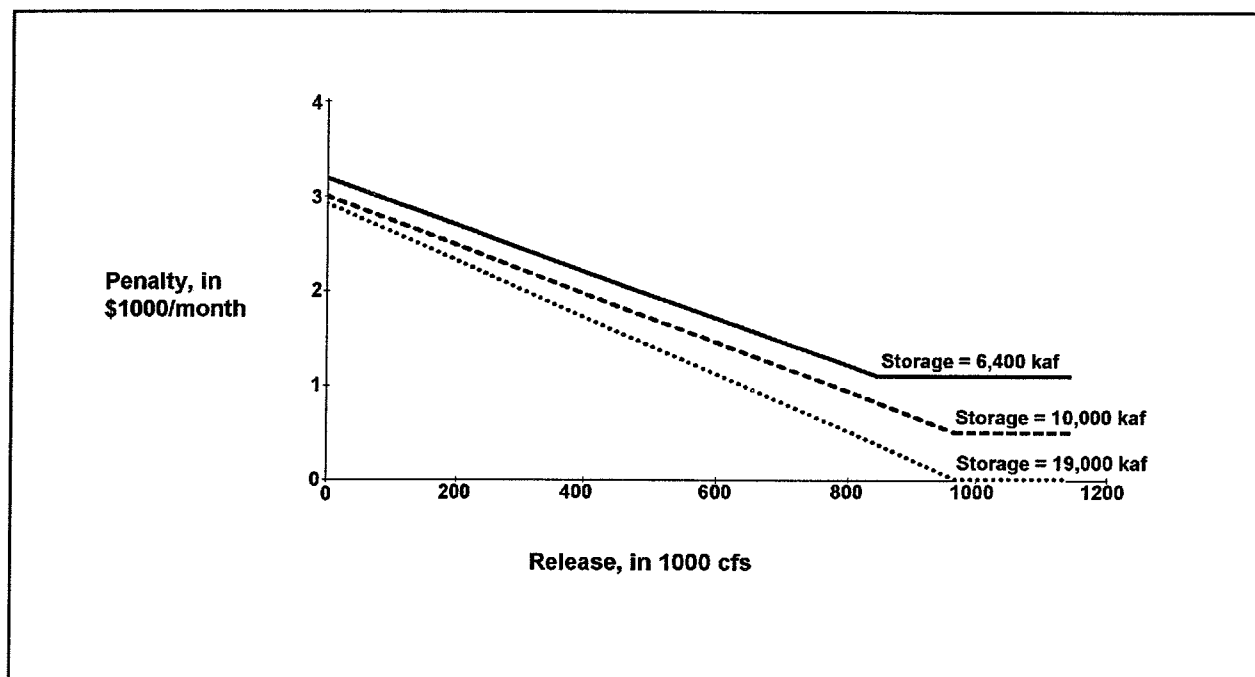
FIGURE A.8 Typical Hydropower Penalty Function

To find the optimal-flow allocation in a system with hydropower, HEC-PRM uses a successive LP algorithm similar to those proposed by Grygier and Stedinger (1985), Martin (1982), and Reznicek and Simonovic (1990). In summary, the algorithm finds the optimal water allocation for hydropower as follows:

Step 1: It makes an initial estimate of storage for each reservoir each period.

Step 2: For each reservoir each period, it selects the penalty function for storage "nearest" the estimate from step 1. Thus, the nonlinear function of release and head is approximated as a linear function of release at the estimated head.

Step 3: It adjusts the network arc costs to correspond to the selected release-related function. All penalty functions for other goals and purposes remain unchanged.

Step 4: It solves the resulting linear problem with the specialized simplex algorithm.

Step 5: With the results of step 4, it compares the computed storages with the assumed storages. If the difference exceeds a pre-specified tolerance, the algorithm adjusts the assumed storages, and returns to step 2. Otherwise, it stops with the optimal releases.

A.6 HEC-PRM Software is General Purpose

The HEC-PRM software is a general-purpose package (USACE, 1991b, 1991c) that consists of a program manager (MENUPRM); a database manager (HEC-DSS); database display, reporting, and additional analysis software; a network generator and a solver. Figure A.9 shows these components and illustrates how information flows between the components. The software executes on an IBM-compatible personal computer.

A.6.1 Program Manager. The program manager, designated MENUPRM (USACE, 1991b), provides the user with easy access to HEC-PRM and the support programs. With MENUPRM, the user can:

• Execute programs of the HEC-PRM package, including the network generator, network solver, and display software;

• Open, create, edit, delete, view, and print files; and

• Execute the HEC-DSS utility programs to analyze further results stored with the HEC-DSS.

A.6.2 Database Manager. The HEC-PRM package uses the HEC Data Storage System, HEC-DSS (USACE, 1990d). HEC-DSS provides a systematic means for organizing, storing, retrieving, manipulating, and sorting the mass of time-series data and penalty functions necessary.
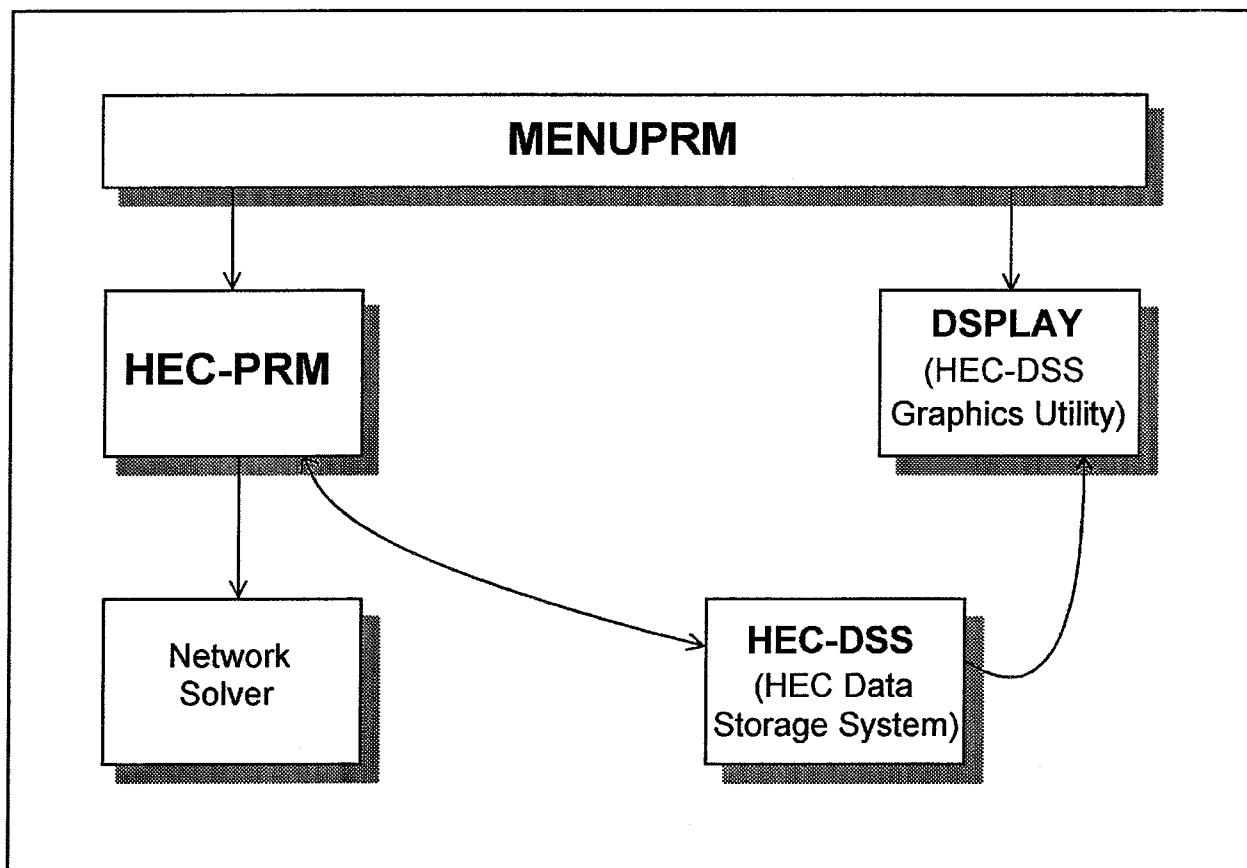
FIGURE A.9 Components of HEC-PRM Software Package

A variety of HEC-DSS utility programs are accessible through MENUPRM. These permit the program user to manipulate data necessary for reservoir-system analysis with HEC-PRM. For example, a utility program is available to convert penalty functions from spreadsheet format to the HEC-DSS format. Another program is available to compute the parameters of a piecewise-linear approximation of a nonlinear penalty function.

A.6.3 Display, Reporting, and Additional Analysis. HEC-PRM's prescribed system flows, releases, and storages are stored with the HEC-DSS. This expedites subsequent analysis of results. For example, flow-duration functions at any system location can be computed with HEC program MATHPK (USACE, 1991d), which accesses data stored with HEC-DSS.

The HEC-PRM package uses program DSPLAY for plotting time-series and X-Y data. DSPLAY reads information directly from HEC-DSS and selects automatically appropriate engineering-drawing scales and plot types. When used with "macros," DSPLAY will plot pre-defined key system variables. This permits the HEC-PRM package to be tailored to any reservoir system.

A.6.4 Network Generator. As formulated, the reservoir-operation problem is defined in terms of nodes and arcs. The network generator defines these arcs and nodes from a description of system reservoirs, interconnecting channels, diversions, and hydropower facilities. For each network node, the generator defines known inflow or local flow by accessing the reservoir inflow and local flow data stored in the database. For each arc, the generator defines the upper and lower bounds and unit flow penalty by accessing penalty functions stored in the specialized database.

A.6.5 Network Solver. The optimal network flows are found with a generalized-network solver. This solver is a primal simplex solver. Details of the algorithm are presented by Jensen (1991a, 1991b).

Appendix B

HEC-PRM Hydropower Algorithm

Appendix B

HEC-PRM Hydropower Algorithm

HEC-PRM evaluates the most economical reservoir operation for the generation of hydroelectric power by the method of successive linear approximation. This techniques has been used by Martin (1982), Grygier and Stedinger (1985), and Reznicek and Simonovic (1990) in similar reservoir operational analyses. The nonlinear power generation penalty function for each reservoir is approximated as a family of penalty curves. Each curve is associated with a specific reservoir storage level and estimates the power penalty as a convex, piecewise-linear function of the hydropower releases when the reservoir storage is held constant.

Given the average reservoir storage and the hydropower release for a month, the penalty curve associated with the closest storage level may be used to approximate the power generation penalty as a piecewise-linear function of that release rate. The impact of storage changes on the power penalties is approximated by estimating the rate of change of power penalties per unit change in storage using the penalty functions associated with the next larger and smaller discrete storage levels. The network arc bounds and costs are adjusted to reflect the new approximations. These adjustments include constraining each hydropower release rate to change no more than a certain percentage of its current value so that the approximation to the current penalty function remains reasonable.

The network model is solved again and, if the new solution is lower in penalty cost than the previous, then the approximation process is repeated based on the new solution. However, if the new solution has a higher cost, then the previous solution is retrieved and the percentage factor for changes in hydropower releases is reduced by half. The network is then revised and solved anew. When the release factor reaches a minimum value, the algorithm terminates and retains the lowest cost solution found to that point as the optimal solution to the network model.

The algorithm for the hydropower generation problem consists of the following steps.

1. **SET ISWIT = 0**

2. **SELECT NEXT HYDROPOWER LINK I.**

3. **DETERMINE RESERVOIR J CONTROLLING HYDROPOWER RELEASES IN LINK I.**

4. **DETERMINE APPROPRIATE HYDROPOWER PENALTY CURVE**

    a. Calculate the average storage $S_{j,m}$ for month m.

b. Determine hydropower penalty curve t' most appropriate for hydropower link for month m.

    i. Retrieve storage SP_t corresponding to each penalty curve t.

    ii. Find curve t' from all t which

$$minimizes \ |S_{j,m} - SP_t|$$

    iii. Retrieve prior penalty curve $t*$ used.

    iv. If $t* = t'$, then go to Step 5.a.

    v. ISWIT = 1

    vi. Set $t* = t'$.

5. ADJUST STORAGE PENALTIES FOR CONTROLLING RESERVOIR J.

a. Retrieve storage SP_t corresponding to each penalty curve t.

b. Find curves n' and $n' + 1$ which satisfy

$$SP_1 \leq \cdots \leq SP_{n'-1} \leq SP_{n'} \leq S_{j,m} \leq SP_{n'+1} \leq SP_{n'+2} \leq \cdots$$

c. Retrieve current total flow Q_i in hydropower link i.

d. Interpolate values for hydropower penalty $P(n', Q_i)$ and $P(n' + 1, Q_i)$ for flow Q_i from curves n' and $n'+1$.

e. Calculate rate of change PS_i in hydropower penalty by $PS_i = (P(n',Q_i)-P(n'+1,Q_i))/(SP_{n'}-SP_{n'+1})$.

f. Add $PS_i/2$ to the cost of each of the end-of-month storage arcs for reservoir J in months m-1 and m.

6. ADJUST PIECEWISE LINEAR PENALTY FUNCTION ON HYDRO LINKS FOR NEW PENALTY CURVE $t*$.

a. Replace unit costs in line segment arcs with those of penalty curve $t*$.

b. Retrieve current total flow Q_i in hydropower link i, current range factor $\alpha<1$, nonzero flow tolerance limit (QTOL), and maximum allowed flow (Q_{max}) in link i. Retrieve and put into the network model the **original** upper bounds (UB) for link i corresponding to hydropower penalty curve $t*$.

c. Set ranges for flow according to allowed variation of QMIN $\leq Q_i \leq$ QMAX,

<u>where</u>
  QMIN = Q_i - ($\alpha*Q_i$) and
  QMAX = Minimum {Q_i + ($\alpha*Q_i$), Q_{max}},
<u>unless</u> $Q_i \le$ QTOL then
  QMIN = 0 and QMAX = Maximum {Q_i, $\alpha*Q_{max}$}.

d. Determine the line segment k′ of the penalty curve containing QMIN.

e. Set lower bound equal to upper bound UB_k for all line segments k < k′.

f. Set lower bound $LB_{k′}$ on segment k′ equal to

$$LB_{k'} = QMIN - \sum_{k=1}^{k'-1} UB_K$$

g. Determine the line segment k″ of the penalty curve containing QMAX.

h. Set upper bound equal to zero for all line segments k > k″.

i. Set upper bound $UB_{k″}$ on segment k″ equal to

$$UB_{k''} = QMAX - \sum_{k=1}^{k''-1} UB_K$$

j. Determine the line segment k‴ of the penalty curve containing Q_i.

k. Set Q_k = UB_k for all line segments k < k‴.

l. Set $Q_{k‴}$ equal to

$$Q_{k'''} = Q_i - \sum_{k=1}^{k'''-1} UB_K$$

m. Set Q_k = 0 for all line segments k > k‴.

7. IF ALL HYDROPOWER LINKS HAVE BEEN CONSIDERED THEN GO TO STEP 8. IF NOT THEN GO TO STEP 2.

8. IF $\alpha < \alpha_{min}$ (minimum allowed α) THEN STOP. OTHERWISE GO TO STEP 9.

9. SOLVE NETWORK MODEL USING CURRENT FLOW SOLUTION

10. **IF NO REDUCTION IN SYSTEM PENALTY COSTS THEN RETRIEVE PRIOR SOLUTION HAVING LOWEST PENALTY COST, SET $\alpha = \alpha/2$, AND GO TO STEP 1. OTHERWISE GO TO STEP 11.**

11. **REPLACE BEST SOLUTION WITH THE LAST SOLUTION AND GO TO STEP 1.**

Appendix C

References

Appendix C

References

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Appendix D

HEC-PRM Input

Appendix D

HEC-PRM Input

Table of Contents

Appendix D

HEC-PRM Input

For completeness, this appendix includes the HEC-PRM program input files used by HEC in analysis of Columbia River System operation. The following are included:

Alternative 1: Operation with Existing Canadian Treaty

HEC-PRM Input

```
..          ALT1
ZW          F=ALT1
..
..          50-Year Period of Analysis
..
..          ALTERNATIVE 1: OPTIMIZATION OF ALL US AND CANADIAN TREATY RESERVOIRS;
..            CURRENT TREATY STORAGE
..
..          1) MICA LIVE STORAGE IS 7,000,000 ACFT
..          2) CORRA LINN STORAGE PENALTIES ARE BASED ON IJC RULE CURVE
..          3) PUMPING FROM GRANDE COULEE TO THE COLUMBIA BASIN PROJECT
..             IS BASED ON 1980 LEVEL DATA
..          4) FLOW DATA ARE 1980 LEVEL OF DEVELOPMENT
..          5) PENALTY DATA ARE PHASE 1.5 WITH MODIFICATIONS
..
..          Non-Economic Penalty for Hydropower at Corra Linn to constrain Flow.
..          Duncan release penalty to constrain maximum flow to 20,000 cfs (1206ka
..
IDENT       S SOURCE    SINK
TIME        JUL1928 JUN1978
..
J11.0E-05 1.0E+06          1.0        1.0          1        3
..
NODE        MICA_P       20075.0        0.1    20075.0
ND          Mica Reservoir Power Penalties
NODE        MICA
ND          Mica Reservoir Non-Power Penalties
NODE        ARROW         7327.0        0.1     7327.0
ND          Arrow Reservoir
NODE        H.HORSE_P     3647.1        0.1     3647.1
ND          Hungry Horse Reservoir Power Penalties
NODE        H.HORSE
ND          Hungry Horse Reservoir Non-Power Penalties
NODE        C.FALLS
ND          Columbia Falls
NODE        KERR_P        1791.0        0.1     1791.0
ND          Kerr Res-Flathead Lake Power Penalties
NODE        KERR
ND          Kerr Res-Flathead Lake Non-Power Penalties
NODE        THOMPSON_P     999.0        0.1      999.0
ND          Thompson Falls, Noxon and Cabinet Power Penalties
NODE        THOMPSON
ND          Thompson Falls, Noxon and Cabinet Non-Power Penalties
NODE        ALBENI_P      1586.7        0.1     1586.7
ND          Albeni Falls, Box Canyon and Boundary Power Penalties
NODE        ALBENI
ND          Albeni Falls, Box Canyon and Boundary Non-Power Penalties
NODE        LIBBY_P       5869.4        0.1     5869.4
ND          Libby Reservoir Power Penalties
NODE        LIBBY
ND          Libby Reservoir Non-Power Penalties
NODE        BONNERS
ND          Bonners Ferry
NODE        DUNCAN        1398.6        0.1     1398.6
ND          Duncan Reservoir
NODE        CORRA.L_P      570.0        0.1      570.0
ND          Corra Linn Power Penalties
NODE        CORRA.L
ND          Corra Linn Non-Power Penalties
NODE        COULEE_P      9107.0        0.1     9107.0
ND          Grand Coulee and Chief Joseph Power Penalties
NODE        COULEE
ND          Grand Coulee and Chief Joseph Non-Power Penalties
```

```
NODE        WELLS_P          999.0       0.1       999.0
ND          Wells Reservoir Power Penalties
NODE        WELLS
ND          Wells Reservoir Non-Power Penalties
NODE        ROCKY.R_P        999.0       0.1       999.0
ND          Rocky Reach Reservoir Power Penalties
NODE        ROCKY.R
ND          Rocky Reach Reservoir Non-Power Penalties
NODE        ROCK.IS_P        999.0       0.1       999.0
ND          Rock Island, Wanapum and Priest Rapids Power Penalties
NODE        ROCK.IS
ND          Rock Island, Wanapum and Priest Rapids Non-Power Penalties
NODE        DWORSHAK_P       3468.0      0.1       3468.0
ND          Dworshak Reservoir Power Penalties
NODE        DWORSHAK
ND          Dworshak Reservoir Non-Power Penalties
NODE        SPALDING
ND          Spalding
NODE        BROWNLEE_P       1426.7      0.1       1426.7
ND          Brownlee, Oxbow, and Hells Canyon Power Penalties
NODE        BROWNLEE
ND          Brownlee, Oxbow, and Hells Canyon Non-Power Penalties
NODE        GRANITE_P        1825.0      0.1       1825.0
ND          L.Granite\Little Goose\L.Monumental\Ice Harbor Power Penalties
NODE        GRANITE
ND          L.Granite\Little Goose\L.Monumental\Ice Harbor Non-Power Penalties
NODE        MCNARY_P         1350.0      0.1       1350.0
ND          Mc Nary Reservoir Power Penalties
NODE        MCNARY
ND          Mc Nary Reservoir Non-Power Penalties
NODE        J.DAY_P          2523.0      0.1       2523.0
ND          John Day Reservoir Power Penalties
NODE        J.DAY
ND          John Day Reservoir Non-Power Penalties
NODE        DALLES_P         999.0       0.1       999.0
ND          The Dalles and Bonneville Reservoirs Power Penalties
NODE        DALLES
ND          The Dalles and Bonneville Reservoirs Non-Power Penalties

LINK        DIVR      S_SOURCE   SINK      1.0         0.0
LD          Continuity Link

LINK        INFLOW    S_SOURCE   MICA_P    1.0         0.0
LD          Inflow to Mica Reservoir
IN          B=MICA_P  C=FLOW_LOC E=1MON F=INC-NAT80

..          7000 KAF TREATY STORAGE
LINK        RSTORAGE  MICA_P     MICA_P    1.0         0.0         13075.0     20075.
LD          Storage in Mica Reservoir
PS          MO=JAN-DEC     B=MICA_P   C=STOR-PNLTY_EDT   E=JAN   F=ZERO

LINK        HREL      MICA_P     MICA
LD          Power Release from Mica
PQ          MO=JAN-DEC     B=MICA_P        C=FLOW-PNLTY_HPE E=JAN F=ZERO

..          Since there are no penalty functions for Mica specify minimum flow
..          "Seasonal" Minimum Release from Mica of 10,000 cfs (603.7 KAF)
..          is represented by two seasonal flow penalty curves
LINK        RRELEASE  MICA       ARROW
LD          Other Releases from Mica to Arrow
PQ          MO=JAN         B=MICA_P        C=FLOW-PNLTY_EDT E=JAN F=
PQ          MO=FEB E=FEB
PQ          MO=MAR E=MAR
PQ          MO=APR E=APR
PQ          MO=MAY E=MAY
PQ          MO=JUN E=JUN
PQ          MO=JUL E=JUL
PQ          MO=AUG E=AUG
PQ          MO=SEP E=SEP
PQ          MO=OCT E=OCT
PQ          MO=NOV E=NOV
PQ          MO=DEC E=DEC
```

```
LINK        INFLOW    S_SOURCE  ARROW      1.0          0.0
LD          Inflow to Arrow Reservoir
IN          B=ARROW C=FLOW_LOC E=1MON F=INC-NAT80

LINK        RSTORAGE  ARROW     ARROW      1.0          0.0          227.0       7327.0
LD          Storage in Arrow Reservoir
PS          MO=JAN-DEC     B=ARROW     C=STOR-PNLTY_EDT   E=JAN   F=ZERO

..          Since there are no penalty functions for Arrow specify minimum flow
..          Minimum Release from Arrow is 5,000 cfs (301.9 KAF)
LINK        RRELEASE  ARROW     COULEE_P                            301.9
LD          Other Releases from Arrow to Coulee
PQ          MO=JAN-DEC     B=ARROW               C=FLOW-PNLTY_EDT E=JAN F=ZERO

LINK        INFLOW    S_SOURCE  H.HORSE_P 1.0          0.0
LD          Inflow to Hungry Horse Reservoir
IN          B=H.HORSE_P C=FLOW_LOC E=1MON F=INC-NAT80

LINK        RSTORAGE  H.HORSE_P H.HORSE_P 1.0          0.0          486.0       3647.1
LD          Storage in Hungry Horse Reservoir
PS          MO=JAN         B=H.HORSE_P  C=STOR-PNLTY_EDT   E=JAN   F=
PS          MO=FEB E=FEB
PS          MO=MAR E=MAR
PS          MO=APR E=APR
PS          MO=MAY E=MAY
PS          MO=JUN E=JUN
PS          MO=JUL E=JUL
PS          MO=AUG E=AUG
PS          MO=SEP E=SEP
PS          MO=OCT E=OCT
PS          MO=NOV E=NOV
PS          MO=DEC E=DEC

LINK        HREL      H.HORSE_P H.HORSE
LD          Power Release from Hungry Horse Reservoir
PQ          MO=JAN-FEB B=H.HORSE_P          C=FLOW-PNLTY_HPE E=DEC-FEB
PQ          MO=MAR     B=H.HORSE_P          C=FLOW-PNLTY_HPE E=MAR_NOV
PQ          MO=APR-MAY B=H.HORSE_P          C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ          MO=JUN-SEP B=H.HORSE_P          C=FLOW-PNLTY_HPE E=JUN-SEP
PQ          MO=OCT     B=H.HORSE_P          C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ          MO=NOV     B=H.HORSE_P          C=FLOW-PNLTY_HPE E=MAR_NOV
PQ          MO=DEC     B=H.HORSE_P          C=FLOW-PNLTY_HPE E=DEC-FEB

LINK        RRELEASE  H.HORSE   C.FALLS                             24.1
LD          Other Releases from Hungry Horse Reservoir to Columbia Falls
PQ          MO=JAN-DEC     B=H.HORSE_P          C=FLOW-PNLTY_EDT E=JAN F=ZERO

LINK        INFLOW    S_SOURCE  C.FALLS    1.0          0.0
LD          Inflow to Columbia Falls
IN           B=C.FALLS C=FLOW_LOC E=1MON F=INC-NAT80

LINK        CHANNEL   C.FALLS   KERR_P
LD          Channel from Columbia Falls to Kerr Reservoir
PQ          MO=JAN         B=C.FALLS            C=FLOW-PNLTY_EDT E=JAN F=
PQ          MO=FEB E=FEB
PQ          MO=MAR E=MAR
PQ          MO=APR E=APR
PQ          MO=MAY E=MAY
PQ          MO=JUN E=JUN
PQ          MO=JUL E=JUL
PQ          MO=AUG E=AUG
PQ          MO=SEP E=SEP
PQ          MO=OCT E=OCT
PQ          MO=NOV E=NOV
PQ          MO=DEC E=DEC

LINK        INFLOW    S_SOURCE  KERR_P     1.0          0.0
LD          Inflow to Kerr Reservoir (Flathead Lake)
IN           B=KERR_P C=FLOW_LOC E=1MON F=INC-NAT80
```

```
..          Operational Full Pool is 1791 KAF, 1821.4 is Historic Storage Maximum
..          Historic Max Flow Coincident with Max Stor is 58,800 CFS
LINK        RSTORAGE  KERR_P     KERR_P    1.0        0.0         572.3       9999.0
LD          Storage in Kerr Reservoir
PS          MO=JAN       B=KERR_P C=STOR-PNLTY_EDT   E=JAN F=
PS          MO=FEB E=FEB
PS          MO=MAR E=MAR
PS          MO=APR E=APR
PS          MO=MAY E=MAY
PS          MO=JUN E=JUN
PS          MO=JUL E=JUL
PS          MO=AUG E=AUG
PS          MO=SEP E=SEP
PS          MO=OCT E=OCT
PS          MO=NOV E=NOV
PS          MO=DEC E=DEC

LINK        HREL       KERR_P     KERR
LD          Power Release from Kerr Reservoir
PQ          MO=JAN-FEB B=KERR_P        C=FLOW-PNLTY_HPE E=DEC-FEB F=
PQ          MO=MAR     B=KERR_P        C=FLOW-PNLTY_HPE E=MAR_NOV
PQ          MO=APR-MAY B=KERR_P        C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ          MO=JUN-SEP B=KERR_P        C=FLOW-PNLTY_HPE E=JUN-SEP
PQ          MO=OCT     B=KERR_P        C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ          MO=NOV     B=KERR_P        C=FLOW-PNLTY_HPE E=MAR_NOV
PQ          MO=DEC     B=KERR_P        C=FLOW-PNLTY_HPE E=DEC-FEB

..          Limit Flow from Kerr to 55,000 CFS (3316.0 KAF/MO.)
LINK        RRELEASE  KERR       THOMPSON_P                 90.6        3316.0
LD          Other Releases from Kerr Reservoir to Thompson Falls, Noxon, Cabinet
PQ          MO=JAN       B=KERR_P          C=FLOW-PNLTY_EDT E=JAN F=
PQ          MO=FEB E=FEB
PQ          MO=MAR E=MAR
PQ          MO=APR E=APR
PQ          MO=MAY E=MAY
PQ          MO=JUN E=JUN
PQ          MO=JUL E=JUL
PQ          MO=AUG E=AUG
PQ          MO=SEP E=SEP
PQ          MO=OCT E=OCT
PQ          MO=NOV E=NOV
PQ          MO=DEC E=DEC

LINK        INFLOW    S_SOURCE   THOMPSON_P1.0        0.0
LD          Inflow to Thompson/Noxon/Cabinet
IN          B=THOMPSON_P C=FLOW_LOC E=1MON F=INC-NAT80

LINK        RSTORAGE  THOMPSON_PTHOMPSON_P1.0        0.0         999.0       999.0
LD          Storage in Thompson/Noxon/Cabinet Reservoir
PS          MO=JAN-DEC   B=THOMPSON_P C=STOR-PNLTY_EDT   E=JAN F=ZERO

LINK        HREL       THOMPSON_PTHOMPSON
LD          Power Release from Thompson/Noxon/Cabinet Reservoir
PQ          MO=JAN-FEB B=THOMPSON_P          C=FLOW-PNLTY_HPE E=DEC-FEB F=
PQ          MO=MAR     B=THOMPSON_P          C=FLOW-PNLTY_HPE E=MAR_NOV
PQ          MO=APR-MAY B=THOMPSON_P          C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ          MO=JUN-SEP B=THOMPSON_P          C=FLOW-PNLTY_HPE E=JUN-SEP
PQ          MO=OCT     B=THOMPSON_P          C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ          MO=NOV     B=THOMPSON_P          C=FLOW-PNLTY_HPE E=MAR_NOV
PQ          MO=DEC     B=THOMPSON_P          C=FLOW-PNLTY_HPE E=DEC-FEB

LINK        RRELEASE  THOMPSON  ALBENI_P
LD          Channel from Cabinet to Albeni Falls, Box Canyon, & Boundary Res
PQ          MO=JAN-DEC   B=THOMPSON_P          C=FLOW-PNLTY_EDT E=JAN F=ZERO

LINK        INFLOW    S_SOURCE   ALBENI_P   1.0        0.0
LD          Inflow to Albeni Falls, Box Canyon & Boundary Res
IN          B=ALBENI_P  C=FLOW_LOC E=1MON F=INC-NAT80
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..            Operational Full Pool is 1652.5 KAF, 2084.4 is Historic Storage Maximu
..            Historic Max Flow Coincident with Max Stor is 145,000 CFS (8743 KAF)
LINK          RSTORAGE   ALBENI_P   ALBENI_P   1.0        0.0        446.4      9999.0
LD            Storage in Albeni Falls, Box Canyon and Boundary Res
PS            MO=JAN           B=ALBENI_P C=STOR-PNLTY_EDT  E=JAN F=
PS            MO=FEB E=FEB
PS            MO=MAR E=MAR
PS            MO=APR E=APR
PS            MO=MAY E=MAY
PS            MO=JUN E=JUN
PS            MO=JUL E=JUL
PS            MO=AUG E=AUG
PS            MO=SEP E=SEP
PS            MO=OCT E=OCT
PS            MO=NOV E=NOV
PS            MO=DEC E=DEC

LINK          HREL       ALBENI_P   ALBENI
LD            Power Release from Albeni Reservoir
PQ            MO=JAN-FEB B=ALBENI_P          C=FLOW-PNLTY_HPE E=DEC-FEB
PQ            MO=MAR     B=ALBENI_P          C=FLOW-PNLTY_HPE E=MAR_NOV
PQ            MO=APR-MAY B=ALBENI_P          C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ            MO=JUN-SEP B=ALBENI_P          C=FLOW-PNLTY_HPE E=JUN-SEP
PQ            MO=OCT     B=ALBENI_P          C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ            MO=NOV     B=ALBENI_P          C=FLOW-PNLTY_HPE E=MAR_NOV
PQ            MO=DEC     B=ALBENI_P          C=FLOW-PNLTY_HPE E=DEC-FEB

..            Limit Flow from Albeni to 130,000 CFS (7839 KAF/MO.)
LINK          RRELEASE   ALBENI     COULEE_P                          7839.0
LD            Other Releases from Albeni/Box Canyon/Boundary Res. to Grand Coulee
PQ            MO=JAN           B=ALBENI_P       C=FLOW-PNLTY_EDT E=JAN F=
PQ            MO=FEB E=FEB
PQ            MO=MAR E=MAR
PQ            MO=APR E=APR
PQ            MO=MAY E=MAY
PQ            MO=JUN E=JUN
PQ            MO=JUL E=JUL
PQ            MO=AUG E=AUG
PQ            MO=SEP E=SEP
PQ            MO=OCT E=OCT
PQ            MO=NOV E=NOV
PQ            MO=DEC E=DEC

LINK          INFLOW     S_SOURCE   LIBBY_P    1.0        0.0
LD            Inflow to Libby Reservoir
IN             B=LIBBY_P C=FLOW_LOC E=1MON F=INC-NAT80

LINK          RSTORAGE   LIBBY_P    LIBBY_P    1.0        0.0        889.9      5869.4
LD            Storage in Libby Reservoir
PS            MO=JAN           B=LIBBY_P C=STOR-PNLTY_EDT   E=JAN F=
PS            MO=FEB E=FEB
PS            MO=MAR E=MAR
PS            MO=APR E=APR
PS            MO=MAY E=MAY
PS            MO=JUN E=JUN
PS            MO=JUL E=JUL
PS            MO=AUG E=AUG
PS            MO=SEP E=SEP
PS            MO=OCT E=OCT
PS            MO=NOV E=NOV
PS            MO=DEC E=DEC

LINK          HREL       LIBBY_P    LIBBY
LD            Power Release from Libby Reservoir
PQ            MO=JAN-FEB B=LIBBY_P           C=FLOW-PNLTY_HPE E=DEC-FEB
PQ            MO=MAR     B=LIBBY_P           C=FLOW-PNLTY_HPE E=MAR_NOV
PQ            MO=APR-MAY B=LIBBY_P           C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ            MO=JUN-SEP B=LIBBY_P           C=FLOW-PNLTY_HPE E=JUN-SEP
PQ            MO=OCT     B=LIBBY_P           C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ            MO=NOV     B=LIBBY_P           C=FLOW-PNLTY_HPE E=MAR_NOV
PQ            MO=DEC     B=LIBBY_P           C=FLOW-PNLTY_HPE E=DEC-FEB
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LINK        RRELEASE  LIBBY      BONNERS                          181.1
LD          Other Releases from Libby Reservoir to Bonners Ferry
PQ          MO=JAN        B=LIBBY_P        C=FLOW-PNLTY_EDT E=JAN F=
PQ          MO=FEB E=FEB
PQ          MO=MAR E=MAR
PQ          MO=APR E=APR
PQ          MO=MAY E=MAY
PQ          MO=JUN E=JUN
PQ          MO=JUL E=JUL
PQ          MO=AUG E=AUG
PQ          MO=SEP E=SEP
PQ          MO=OCT E=OCT
PQ          MO=NOV E=NOV
PQ          MO=DEC E=DEC


LINK        INFLOW    S_SOURCE  BONNERS   1.0        0.0
LD          Inflow to Bonners Ferry
IN           B=BONNERS C=FLOW_LOC E=1MON F=INC-NAT80


LINK        CHANNEL   BONNERS    CORRA.L_P
LD          Channel from Bonners Ferry to Corra Linn
PQ          MO=JAN        B=BONNERS            C=FLOW-PNLTY_EDT E=JAN F=
PQ          MO=FEB E=FEB
PQ          MO=MAR E=MAR
PQ          MO=APR E=APR
PQ          MO=MAY E=MAY
PQ          MO=JUN E=JUN
PQ          MO=JUL E=JUL
PQ          MO=AUG E=AUG
PQ          MO=SEP E=SEP
PQ          MO=OCT E=OCT
PQ          MO=NOV E=NOV
PQ          MO=DEC E=DEC


LINK        INFLOW    S_SOURCE  DUNCAN    1.0        0.0
LD          Inflow to Duncan Reservoir
IN          B=DUNCAN C=FLOW_LOC E=1MON F=INC-NAT80


LINK        RSTORAGE  DUNCAN     DUNCAN    1.0        0.0        30.0       1398.6
LD          Storage in Duncan Reservoir
PS          MO=JAN-DEC     B=DUNCAN    C=STOR-PNLTY_EDT   E=JAN   F=ZERO


..          Since there are no penalty functions for Duncan specify minimum flow
..          Minimum Release from Duncan is 100 cfs (6.0 KAF)
LINK        RRELEASE  DUNCAN     CORRA.L_P                        6.0
LD          Other Releases from Duncan to Corra.L
PQ          MO=JAN-DEC     B=DUNCAN            C=FLOW-PNLTY_EDT E=JAN F=Q_RESTRICT


LINK        INFLOW    S_SOURCE  CORRA.L_P 1.0        0.0
LD          Inflow to Corra Linn Reservoir
IN           B=CORRA.L_P C=FLOW_LOC E=1MON F=INC-NAT80


..          Operational Full Pool is 817 KAF, 2200 is Historic Storage Maximum
..          Historic Max Flow Coincident with Max Stor is 56,000 CFS  (3377KAF)
..          Upper Limit is Relaxed to Solve Infeasibility Problem
LINK        RSTORAGE  CORRA.L_P CORRA.L_P 1.0        0.0        144.0      9999.0
LD          Storage in Corra Linn Reservoir
PS          MO=JAN        B=CORRA.L_P C=STOR-PNLTY_EDT   E=JAN F=IJC-RULE.C
PS          MO=FEB E=FEB
PS          MO=MAR E=MAR
PS          MO=APR E=AUG
PS          MO=MAY E=AUG
PS          MO=JUN E=AUG
PS          MO=JUL E=AUG
PS          MO=AUG E=AUG
PS          MO=SEP E=DEC
PS          MO=OCT E=DEC
PS          MO=NOV E=DEC
PS          MO=DEC E=DEC
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LINK        HREL        CORRA.L_P CORRA.L                                    3377.0
LD          Power Release from Corra Linn Reservoir
..          PQ          MO=JAN-DEC B=CORRA.L_P          C=FLOW-PNLTY_HPE E= F=Q_RESTR
PQ          MO=JAN-DEC      B=CORRA.L_P          C=FLOW-PNLTY_HPE E=JAN F=ZERO

..          Limit Flow from Corra Linn to 56,000 CFS (3377.0 KAF/MO.)
LINK        RRELEASE    CORRA.L     COULEE_P
LD          Other Releases from Corra Linn Reservoir to Grand Coulee, Chief Joe
PQ          MO=JAN-DEC      B=CORRA.L_P          C=FLOW-PNLTY_EDT E=JAN F=ZERO

LINK        INFLOW    S_SOURCE    COULEE_P  1.0        0.0
LD          Diversion from Grande Coulee to Banks Lake (Negative inflows)
IN           B=COULEE_P C=FLOW_LOC E=1MON F=1980 LEVEL PUMPING

LINK        INFLOW    S_SOURCE    COULEE_P  1.0        0.0
LD          Inflow to Grand Coulee, Chief Joe
IN           B=COULEE_P   C=FLOW_LOC E=1MON F=INC-NAT80

LINK        RSTORAGE  COULEE_P   COULEE_P  1.0        0.0        3879.0     9107.0
LD          Storage in Grand Coulee
PS          MO=JAN          B=COULEE_P C=STOR-PNLTY_EDT   E=JAN F=
PS          MO=FEB E=FEB
PS          MO=MAR E=MAR
PS          MO=APR E=APR
PS          MO=MAY E=MAY
PS          MO=JUN E=JUN
PS          MO=JUL E=JUL
PS          MO=AUG E=AUG
PS          MO=SEP E=SEP
PS          MO=OCT E=OCT
PS          MO=NOV E=NOV
PS          MO=DEC E=DEC

LINK        HREL        COULEE_P   COULEE
LD          Power Release from Grande Coulee Reservoir
PQ          MO=JAN-FEB B=COULEE_P        C=FLOW-PNLTY_HPE E=DEC-FEB
PQ          MO=MAR      B=COULEE_P        C=FLOW-PNLTY_HPE E=MAR_NOV
PQ          MO=APR-MAY B=COULEE_P        C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ          MO=JUN-SEP B=COULEE_P        C=FLOW-PNLTY_HPE E=JUN-SEP
PQ          MO=OCT      B=COULEE_P        C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ          MO=NOV      B=COULEE_P        C=FLOW-PNLTY_HPE E=MAR_NOV
PQ          MO=DEC      B=COULEE_P        C=FLOW-PNLTY_HPE E=DEC-FEB

LINK        RRELEASE  COULEE      WELLS_P
LD          Other Releases from Grand Coulee+Chief Joseph to Wells
PQ          MO=JAN-DEC      B=COULEE_P          C=FLOW-PNLTY_EDT E=JAN F=ZERO

LINK        INFLOW    S_SOURCE    WELLS_P  1.0        0.0
LD          Inflow to Wells
IN          B=WELLS_P C=FLOW_LOC E=1MON F=INC-NAT80

LINK        RSTORAGE  WELLS_P    WELLS_P   1.0        0.0        999.0      999.0
LD          Storage in Wells Reservoir
PS          MO=JAN-DEC      B=WELLS_P C=STOR-PNLTY_EDT   E=JAN F=ZERO

LINK        HREL        WELLS_P     WELLS
LD          Power Release from Wells Reservoir
PQ          MO=JAN-FEB B=WELLS_P        C=FLOW-PNLTY_HPE E=DEC-FEB F=
PQ          MO=MAR      B=WELLS_P        C=FLOW-PNLTY_HPE E=MAR_NOV
PQ          MO=APR-MAY B=WELLS_P        C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ          MO=JUN-SEP B=WELLS_P        C=FLOW-PNLTY_HPE E=JUN-SEP
PQ          MO=OCT      B=WELLS_P        C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ          MO=NOV      B=WELLS_P        C=FLOW-PNLTY_HPE E=MAR_NOV
PQ          MO=DEC      B=WELLS_P        C=FLOW-PNLTY_HPE E=DEC-FEB

LINK        RRELEASE  WELLS       ROCKY.R_P
LD          Channel from Wells to Rocky Reach
PQ          MO=JAN-DEC      B=WELLS_P          C=FLOW-PNLTY_EDT E=JAN F=ZERO

LINK        INFLOW    S_SOURCE    ROCKY.R_P 1.0        0.0
LD          Inflow to Rocky Reach
IN          B=ROCKY.R_P C=FLOW_LOC E=1MON F=INC-NAT80
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LINK        RSTORAGE   ROCKY.R_P ROCKY.R_P 1.0          0.0        999.0        999.0
LD          Storage in Rocky Reach Reservoir
PS          MO=JAN-DEC    B=ROCKY.R_P C=STOR-PNLTY_EDT   E=JAN F=ZERO


LINK        HREL       ROCKY.R_P ROCKY.R
LD          Power Release from Rocky Reach
PQ          MO=JAN-FEB B=ROCKY.R_P          C=FLOW-PNLTY_HPE E=DEC-FEB F=
PQ          MO=MAR      B=ROCKY.R_P          C=FLOW-PNLTY_HPE E=MAR_NOV
PQ          MO=APR-MAY B=ROCKY.R_P          C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ          MO=JUN-SEP B=ROCKY.R_P          C=FLOW-PNLTY_HPE E=JUN-SEP
PQ          MO=OCT      B=ROCKY.R_P          C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ          MO=NOV      B=ROCKY.R_P          C=FLOW-PNLTY_HPE E=MAR_NOV
PQ          MO=DEC      B=ROCKY.R_P          C=FLOW-PNLTY_HPE E=DEC-FEB


LINK        RRELEASE   ROCKY.R    ROCK.IS_P
LD          Channel from Rocky Reach to Rock Island, Wanapum & Priest Rapids
PQ          MO=JAN-DEC    B=ROCKY.R_P            C=FLOW-PNLTY_EDT E=JAN F=ZERO


LINK        INFLOW     S_SOURCE  ROCK.IS_P   1.0         0.0
LD          Inflow to Rock Island, Wanapum & Priest Rapids Reservoirs
IN          B=ROCK.IS_P C=FLOW_LOC E=1MON F=INC-NAT80


LINK        RSTORAGE   ROCK.IS_P ROCK.IS_P 1.0          0.0        999.0        999.0
LD          Storage in Rock Island Reservoir
PS          MO=JAN-DEC    B=ROCK.IS_P C=STOR-PNLTY_EDT   E=JAN F=ZERO


LINK        HREL       ROCK.IS_P ROCK.IS
LD          Power Release from Rocky Island
PQ          MO=JAN-FEB B=ROCK.IS_P          C=FLOW-PNLTY_HPE E=DEC-FEB F=
PQ          MO=MAR      B=ROCK.IS_P          C=FLOW-PNLTY_HPE E=MAR_NOV
PQ          MO=APR-MAY B=ROCK.IS_P          C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ          MO=JUN-SEP B=ROCK.IS_P          C=FLOW-PNLTY_HPE E=JUN-SEP
PQ          MO=OCT      B=ROCK.IS_P          C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ          MO=NOV      B=ROCK.IS_P          C=FLOW-PNLTY_HPE E=MAR_NOV
PQ          MO=DEC      B=ROCK.IS_P          C=FLOW-PNLTY_HPE E=DEC-FEB


LINK        RRELEASE   ROCK.IS    MCNARY_P
LD          Channel from Rock Island, Wanapum, &Priest Rapids to Mc Nary
PQ          MO=JAN-DEC    B=ROCK.IS_P            C=FLOW-PNLTY_EDT E=JAN F=ZERO


LINK        INFLOW     S_SOURCE  DWORSHAK_P   1.0         0.0
LD          Inflow to Dworshak Reservoir
IN          B=DWORSHAK_P C=FLOW_LOC E=1MON F=INC-NAT80


LINK        RSTORAGE   DWORSHAK_PDWORSHAK_P1.0          0.0       1452.2       3468.0
LD          Storage in Dworshak Reservoir
PS          MO=JAN           B=DWORSHAK_P C=STOR-PNLTY_EDT   E=JAN F=
PS          MO=FEB E=FEB
PS          MO=MAR E=MAR
PS          MO=APR E=APR
PS          MO=MAY E=MAY
PS          MO=JUN E=JUN
PS          MO=JUL E=JUL
PS          MO=AUG E=AUG
PS          MO=SEP E=SEP
PS          MO=OCT E=OCT
PS          MO=NOV E=NOV
PS          MO=DEC E=DEC


LINK        HREL       DWORSHAK_PDWORSHAK
LD          Power Release from Dworshak Reservoir
PQ          MO=JAN-FEB B=DWORSHAK_P          C=FLOW-PNLTY_HPE E=DEC-FEB
PQ          MO=MAR      B=DWORSHAK_P          C=FLOW-PNLTY_HPE E=MAR_NOV
PQ          MO=APR-MAY B=DWORSHAK_P          C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ          MO=JUN-SEP B=DWORSHAK_P          C=FLOW-PNLTY_HPE E=JUN-SEP
PQ          MO=OCT      B=DWORSHAK_P          C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ          MO=NOV      B=DWORSHAK_P          C=FLOW-PNLTY_HPE E=MAR_NOV
PQ          MO=DEC      B=DWORSHAK_P          C=FLOW-PNLTY_HPE E=DEC-FEB


LINK        RRELEASE   DWORSHAK   SPALDING                    60.4
LD          Other Releases from Dworshak Reservoir to Spalding
PQ          MO=JAN-DEC    B=DWORSHAK_P            C=FLOW-PNLTY_EDT E=JAN F=ZERO
```

```
LINK        INFLOW    S_SOURCE  SPALDING  1.0       0.0
LD          Inflow to Spalding
IN          B=SPALDING C=FLOW_LOC E=1MON F=INC-NAT80

LINK        CHANNEL   SPALDING  GRANITE_P
LD          Channel from Spalding to Granite/Goose/Monumental/Ice Harbor
PQ          MO=JAN     B=SPALDING              C=FLOW-PNLTY_EDT E=JAN F=
PQ          MO=FEB E=FEB
PQ          MO=MAR E=MAR
PQ          MO=APR E=APR
PQ          MO=MAY E=MAY
PQ          MO=JUN E=JUN
PQ          MO=JUL E=JUL
PQ          MO=AUG E=AUG
PQ          MO=SEP E=SEP
PQ          MO=OCT E=OCT
PQ          MO=NOV E=NOV
PQ          MO=DEC E=DEC

LINK        INFLOW    S_SOURCE  BROWNLEE_P1.0      0.0
LD          Inflow to Brownlee, Oxbow & Hells Canyon Reservoirs
IN          B=BROWNLEE_P C=FLOW_LOC E=1MON F=INC-NAT80

LINK        RSTORAGE  BROWNLEE_PBROWNLEE_P1.0       0.0        431.7     1426.7
LD          Storage in Brownlee, Oxbow & Hells Canyon Reservoirs
PS          MO=JAN-DEC    B=BROWNLEE_P C=STOR-PNLTY_EDT  E=JAN F=ZERO

LINK        HREL      BROWNLEE_PBROWNLEE
LD          Power Release from Brownlee Reservoir
PQ          MO=JAN-FEB B=BROWNLEE_P        C=FLOW-PNLTY_HPE E=DEC-FEB F=
PQ          MO=MAR     B=BROWNLEE_P        C=FLOW-PNLTY_HPE E=MAR_NOV
PQ          MO=APR-MAY B=BROWNLEE_P        C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ          MO=JUN-SEP B=BROWNLEE_P        C=FLOW-PNLTY_HPE E=JUN-SEP
PQ          MO=OCT     B=BROWNLEE_P        C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ          MO=NOV     B=BROWNLEE_P        C=FLOW-PNLTY_HPE E=MAR_NOV
PQ          MO=DEC     B=BROWNLEE_P        C=FLOW-PNLTY_HPE E=DEC-FEB

LINK        RRELEASE  BROWNLEE  GRANITE_P                      301.9
LD          Other Releases from Brownlee/Oxbow/Hells Canyon to Granite/...
PQ          MO=JAN-DEC    B=BROWNLEE_P         C=FLOW-PNLTY_EDT E=JAN F=ZERO

LINK        INFLOW    S_SOURCE  GRANITE_P 1.0      0.0
LD          Inflow to Lower Granite thru Ice Harbor Reservoirs
IN          B=GRANITE_P  C=FLOW_LOC E=1MON F=INC-NAT80

..          Lower limit = 144.0 based on Run-of-River conditions (Four Reservoirs)
LINK        RSTORAGE  GRANITE_P GRANITE_P 1.0                  144.0     1825.0
LD          Storage in Granite Reservoir
PS          MO=JAN        B=GRANITE_P C=STOR-PNLTY_EDT   E=JAN  F=
PS          MO=FEB E=FEB
PS          MO=MAR E=MAR
PS          MO=APR E=APR
PS          MO=MAY E=MAY
PS          MO=JUN E=JUN
PS          MO=JUL E=JUL
PS          MO=AUG E=AUG
PS          MO=SEP E=SEP
PS          MO=OCT E=OCT
PS          MO=NOV E=NOV
PS          MO=DEC E=DEC

LINK        HREL      GRANITE_P GRANITE
LD          Power Release from Granite Reservoir
PQ          MO=JAN-FEB B=GRANITE_P         C=FLOW-PNLTY_HPE E=DEC-FEB
PQ          MO=MAR     B=GRANITE_P         C=FLOW-PNLTY_HPE E=MAR_NOV
PQ          MO=APR-MAY B=GRANITE_P         C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ          MO=JUN-SEP B=GRANITE_P         C=FLOW-PNLTY_HPE E=JUN-SEP
PQ          MO=OCT     B=GRANITE_P         C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ          MO=NOV     B=GRANITE_P         C=FLOW-PNLTY_HPE E=MAR_NOV
PQ          MO=DEC     B=GRANITE_P         C=FLOW-PNLTY_HPE E=DEC-FEB
```

```
LINK        RRELEASE   GRANITE    MCNARY_P
LD          Release from Granite/Goose/Monumental/Ice Harbor to McNary Reservoir
PQ          MO=JAN        B=GRANITE_P          C=FLOW-PNLTY_EDT E=JAN F=
PQ          MO=FEB E=FEB
PQ          MO=MAR E=MAR
PQ          MO=APR E=APR
PQ          MO=MAY E=MAY
PQ          MO=JUN E=JUN
PQ          MO=JUL E=JUL
PQ          MO=AUG E=AUG
PQ          MO=SEP E=SEP
PQ          MO=OCT E=OCT
PQ          MO=NOV E=NOV
PQ          MO=DEC E=DEC


LINK        INFLOW     S_SOURCE  MCNARY_P  1.0          0.0
LD          Inflow to Mc Nary Reservoir
IN          B=MCNARY_P C=FLOW_LOC E=1MON F=INC-NAT80


LINK        RSTORAGE   MCNARY_P   MCNARY_P  1.0                    1170.0    1350.0
LD          Storage in Mc Nary Reservoir
PS          MO=JAN        B=MCNARY_P C=STOR-PNLTY_EDT  E=JAN F=
PS          MO=FEB E=FEB
PS          MO=MAR E=MAR
PS          MO=APR E=APR
PS          MO=MAY E=MAY
PS          MO=JUN E=JUN
PS          MO=JUL E=JUL
PS          MO=AUG E=AUG
PS          MO=SEP E=SEP
PS          MO=OCT E=OCT
PS          MO=NOV E=NOV
PS          MO=DEC E=DEC


LINK        HREL       MCNARY_P   MCNARY
LD          Power Release from McNary Reservoir
PQ          MO=JAN-FEB B=MCNARY_P         C=FLOW-PNLTY_HPE E=DEC-FEB
PQ          MO=MAR     B=MCNARY_P         C=FLOW-PNLTY_HPE E=MAR_NOV
PQ          MO=APR-MAY B=MCNARY_P         C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ          MO=JUN-SEP B=MCNARY_P         C=FLOW-PNLTY_HPE E=JUN-SEP
PQ          MO=OCT     B=MCNARY_P         C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ          MO=NOV     B=MCNARY_P         C=FLOW-PNLTY_HPE E=MAR_NOV
PQ          MO=DEC     B=MCNARY_P         C=FLOW-PNLTY_HPE E=DEC-FEB


LINK        RRELEASE   MCNARY     J.DAY_P
LD          Channel from Mc Nary to John Day
PQ          MO=JAN-DEC    B=MCNARY_P          C=FLOW-PNLTY_EDT E=JAN F=ZERO


LINK        INFLOW     S_SOURCE  J.DAY_P   1.0          0.0
LD          Inflow to John Day
IN          B=J.DAY_P C=FLOW_LOC E=1MON F=INC-NAT80


LINK        RSTORAGE   J.DAY_P   J.DAY_P   1.0                    1989.0    2523.0
LD          Storage in John Day Reservoir
PS          MO=JAN        B=J.DAY_P  C=STOR-PNLTY_EDT  E=JAN  F=
PS          MO=FEB E=FEB
PS          MO=MAR E=MAR
PS          MO=APR E=APR
PS          MO=MAY E=MAY
PS          MO=JUN E=JUN
PS          MO=JUL E=JUL
PS          MO=AUG E=AUG
PS          MO=SEP E=SEP
PS          MO=OCT E=OCT
PS          MO=NOV E=NOV
PS          MO=DEC E=DEC
```

```
LINK        HREL        J.DAY_P     J.DAY
LD          Power Release from John Day Reservoir
PQ          MO=JAN-FEB  B=J.DAY_P           C=FLOW-PNLTY_HPE  E=DEC-FEB
PQ          MO=MAR      B=J.DAY_P           C=FLOW-PNLTY_HPE  E=MAR_NOV
PQ          MO=APR-MAY  B=J.DAY_P           C=FLOW-PNLTY_HPE  E=APR-MAY_OCT
PQ          MO=JUN-SEP  B=J.DAY_P           C=FLOW-PNLTY_HPE  E=JUN-SEP
PQ          MO=OCT      B=J.DAY_P           C=FLOW-PNLTY_HPE  E=APR-MAY_OCT
PQ          MO=NOV      B=J.DAY_P           C=FLOW-PNLTY_HPE  E=MAR_NOV
PQ          MO=DEC      B=J.DAY_P           C=FLOW-PNLTY_HPE  E=DEC-FEB

LINK        RRELEASE    J.DAY       DALLES_P
LD          Release from John Day to the Dalles & Bonneville Reservoirs
PQ          MO=JAN-DEC   B=J.DAY_P           C=FLOW-PNLTY_EDT  E=JAN  F=ZERO

LINK        INFLOW     S_SOURCE  DALLES_P    1.0        0.0
LD          Inflow to The Dalles & Bonneville Reservoirs
IN          B=DALLES_P  C=FLOW_LOC  E=1MON  F=INC-NAT80

LINK        RSTORAGE   DALLES_P  DALLES_P  1.0          0.0        999.0        999.0
LD          Storage in The Dalles and Bonneville Reservoirs
PS          MO=JAN-DEC   B=DALLES_P  C=STOR-PNLTY_EDT   E=JAN  F=ZERO

LINK        HREL        DALLES_P    DALLES
LD          Power Release from The Dalles
PQ          MO=JAN-FEB  B=DALLES_P          C=FLOW-PNLTY_HPE  E=DEC-FEB  F=
PQ          MO=MAR      B=DALLES_P          C=FLOW-PNLTY_HPE  E=MAR_NOV
PQ          MO=APR-MAY  B=DALLES_P          C=FLOW-PNLTY_HPE  E=APR-MAY_OCT
PQ          MO=JUN-SEP  B=DALLES_P          C=FLOW-PNLTY_HPE  E=JUN-SEP
PQ          MO=OCT      B=DALLES_P          C=FLOW-PNLTY_HPE  E=APR-MAY_OCT
PQ          MO=NOV      B=DALLES_P          C=FLOW-PNLTY_HPE  E=MAR_NOV
PQ          MO=DEC      B=DALLES_P          C=FLOW-PNLTY_HPE  E=DEC-FEB

LINK        RREL        DALLES      SINK
LD          Release from The Dalles & Bonneville to the Sink
PQ          MO=JAN       B=DALLES_P      C=FLOW-PNLTY_EDT E=JAN  F=
PQ          MO=FEB  E=FEB
PQ          MO=MAR  E=MAR
PQ          MO=APR  E=APR
PQ          MO=MAY  E=MAY
PQ          MO=JUN  E=JUN
PQ          MO=JUL  E=JUL
PQ          MO=AUG  E=AUG
PQ          MO=SEP  E=SEP
PQ          MO=OCT  E=OCT
PQ          MO=NOV  E=NOV
PQ          MO=DEC  E=DEC

STOP
```

Alternative 2: Operation without Hydropower Objective

HEC-PRM Input

```
..        ALT2
ZW        F=ALT2
..
..        50-Year Period of Analysis
..
..        ALTERNATIVE 2: OPTIMIZATION OF ALL US AND CANADIAN TREATY RESERVOIRS;
..           CURRENT TREATY STORAGE; WITHOUT HYDROPOWER PENALTIES
..
..        1) MICA LIVE STORAGE IS 7,000,000 ACFT
..        2) CORRA LINN STORAGE PENALTIES ARE BASED ON IJC RULE CURVE
..        3) PUMPING FROM GRANDE COULEE TO THE COLUMBIA BASIN PROJECT
..              IS BASED ON 1980 LEVEL DATA
..        4) FLOW DATA ARE 1980 LEVEL OF DEVELOPMENT
..        5) PENALTY DATA ARE PHASE 1.5 WITH MODIFICATIONS
..
..        Non-Economic Penalty for Hydropower at Corra Linn to constrain Flow.
..        Duncan release penalty to constrain maximum flow to 20,000 cfs (1206ka
..        To simulate realistic operation at hydropower sites releases are
..        limited to hydraulic capacity with non-economic penalty data, F=HY-CAP
..
IDENT     S_SOURCE     SINK
TIME      JUL1928 JUN1978
..
J11.0E-05 1.0E+06         1.0         1.0         1         3
..
NODE      MICA_P        20075.0        0.1     20075.0
ND        Mica Reservoir Power Penalties
NODE      MICA
ND        Mica Reservoir Non-Power Penalties
NODE      ARROW          7327.0        0.1      7327.0
ND        Arrow Reservoir
NODE      H.HORSE_P      3647.1        0.1      3647.1
ND        Hungry Horse Reservoir Power Penalties
NODE      H.HORSE
ND        Hungry Horse Reservoir Non-Power Penalties
NODE      C.FALLS
ND        Columbia Falls
NODE      KERR_P         1791.0        0.1      1791.0
ND        Kerr Res-Flathead Lake Power Penalties
NODE      KERR
ND        Kerr Res-Flathead Lake Non-Power Penalties
NODE      THOMPSON_P      999.0        0.1       999.0
ND        Thompson Falls, Noxon and Cabinet Power Penalties
NODE      THOMPSON
ND        Thompson Falls, Noxon and Cabinet Non-Power Penalties
NODE      ALBENI_P       1586.7        0.1      1586.7
ND        Albeni Falls, Box Canyon and Boundary Power Penalties
NODE      ALBENI
ND        Albeni Falls, Box Canyon and Boundary Non-Power Penalties
NODE      LIBBY_P        5869.4        0.1      5869.4
ND        Libby Reservoir Power Penalties
NODE      LIBBY
ND        Libby Reservoir Non-Power Penalties
NODE      BONNERS
ND        Bonners Ferry
NODE      DUNCAN         1398.6        0.1      1398.6
ND        Duncan Reservoir
NODE      CORRA.L_P       570.0        0.1       570.0
ND        Corra Linn Power Penalties
NODE      CORRA.L
ND        Corra Linn Non-Power Penalties
NODE      COULEE_P       9107.0        0.1      9107.0
ND        Grand Coulee and Chief Joseph Power Penalties
NODE      COULEE
```

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ND           Grand Coulee and Chief Joseph Non-Power Penalties
NODE         WELLS_P          999.0        0.1        999.0
ND           Wells Reservoir Power Penalties
NODE         WELLS
ND           Wells Reservoir Non-Power Penalties
NODE         ROCKY.R_P        999.0        0.1        999.0
ND           Rocky Reach Reservoir Power Penalties
NODE         ROCKY.R
ND           Rocky Reach Reservoir Non-Power Penalties
NODE         ROCK.IS_P        999.0        0.1        999.0
ND           Rock Island, Wanapum and Priest Rapids Power Penalties
NODE         ROCK.IS
ND           Rock Island, Wanapum and Priest Rapids Non-Power Penalties
NODE         DWORSHAK_P       3468.0       0.1        3468.0
ND           Dworshak Reservoir Power Penalties
NODE         DWORSHAK
ND           Dworshak Reservoir Non-Power Penalties
NODE         SPALDING
ND           Spalding
NODE         BROWNLEE_P       1426.7       0.1        1426.7
ND           Brownlee, Oxbow, and Hells Canyon Power Penalties
NODE         BROWNLEE
ND           Brownlee, Oxbow, and Hells Canyon Non-Power Penalties
NODE         GRANITE_P        1825.0       0.1        1825.0
ND           L.Granite\Little Goose\L.Monumental\Ice Harbor Power Penalties
NODE         GRANITE
ND           L.Granite\Little Goose\L.Monumental\Ice Harbor Non-Power Penalties
NODE         MCNARY_P         1350.0       0.1        1350.0
ND           Mc Nary Reservoir Power Penalties
NODE         MCNARY
ND           Mc Nary Reservoir Non-Power Penalties
NODE         J.DAY_P          2523.0       0.1        2523.0
ND           John Day Reservoir Power Penalties
NODE         J.DAY
ND           John Day Reservoir Non-Power Penalties
NODE         DALLES_P         999.0        0.1        999.0
ND           The Dalles and Bonneville Reservoirs Power Penalties
NODE         DALLES
ND           The Dalles and Bonneville Reservoirs Non-Power Penalties

LINK         DIVR      S_SOURCE   SINK       1.0         0.0
LD           Continuity Link

LINK         INFLOW    S_SOURCE   MICA_P     1.0         0.0
LD           Inflow to Mica Reservoir
IN           B=MICA_P  C=FLOW_LOC E=1MON F=INC-NAT80

..           7000 KAF TREATY STORAGE
LINK         RSTORAGE  MICA_P     MICA_P     1.0         0.0        13075.0    20075.
LD           Storage in Mica Reservoir
PS           MO=JAN-DEC     B=MICA_P     C=STOR-PNLTY_EDT   E=JAN  F=ZERO

LINK         HREL      MICA_P     MICA
LD           Power Release from Mica
PQ           MO=JAN-DEC     B=MICA_P          C=FLOW-PNLTY_HPE E=JAN F=ZERO

..           Since there are no penalty functions for Mica specify minimum flow
..           "Seasonal" Minimum Release from Mica of 10,000 cfs (603.7 KAF)
..           is represented by two seasonal flow penalty curves
LINK         RRELEASE  MICA       ARROW
LD           Other Releases from Mica to Arrow
PQ           MO=JAN         B=MICA_P     C=FLOW-PNLTY_EDT E=JAN F=
PQ           MO=FEB E=FEB
PQ           MO=MAR E=MAR
PQ           MO=APR E=APR
PQ           MO=MAY E=MAY
PQ           MO=JUN E=JUN
PQ           MO=JUL E=JUL
PQ           MO=AUG E=AUG
PQ           MO=SEP E=SEP
PQ           MO=OCT E=OCT
PQ           MO=NOV E=NOV
PQ           MO=DEC E=DEC
```

```
LINK        INFLOW    S_SOURCE  ARROW      1.0        0.0
LD          Inflow to Arrow Reservoir
IN          B=ARROW C=FLOW_LOC E=1MON F=INC-NAT80


LINK        RSTORAGE  ARROW      ARROW     1.0        0.0         227.0      7327.0
LD          Storage in Arrow Reservoir
PS          MO=JAN-DEC    B=ARROW     C=STOR-PNLTY_EDT   E=JAN   F=ZERO


..          Since there are no penalty functions for Arrow specify minimum flow
..          Minimum Release from Arrow is 5,000 cfs (301.9 KAF)
LINK        RRELEASE  ARROW      COULEE_P                          301.9
LD          Other Releases from Arrow to Coulee
PQ          MO=JAN-DEC    B=ARROW              C=FLOW-PNLTY_EDT E=JAN F=ZERO


LINK        INFLOW    S_SOURCE  H.HORSE_P 1.0        0.0
LD          Inflow to Hungry Horse Reservoir
IN          B=H.HORSE_P C=FLOW_LOC E=1MON F=INC-NAT80


LINK        RSTORAGE  H.HORSE_P H.HORSE_P 1.0        0.0         486.0      3647.1
LD          Storage in Hungry Horse Reservoir
PS          MO=JAN        B=H.HORSE_P  C=STOR-PNLTY_EDT   E=JAN   F=
PS          MO=FEB E=FEB
PS          MO=MAR E=MAR
PS          MO=APR E=APR
PS          MO=MAY E=MAY
PS          MO=JUN E=JUN
PS          MO=JUL E=JUL
PS          MO=AUG E=AUG
PS          MO=SEP E=SEP
PS          MO=OCT E=OCT
PS          MO=NOV E=NOV
PS          MO=DEC E=DEC


LINK        HREL      H.HORSE_P H.HORSE
LD          Power Release from Hungry Horse Reservoir
PQ          MO=JAN-DEC B=H.HORSE_P         C=FLOW-PNLTY_HPE E=JAN F=HY-CAP


LINK        RRELEASE  H.HORSE    C.FALLS                          24.1
LD          Other Releases from Hungry Horse Reservoir to Columbia Falls
PQ          MO=JAN-DEC    B=H.HORSE_P         C=FLOW-PNLTY_EDT E=JAN F=ZERO


LINK        INFLOW    S_SOURCE  C.FALLS    1.0        0.0
LD          Inflow to Columbia Falls
IN           B=C.FALLS C=FLOW_LOC E=1MON F=INC-NAT80


LINK        CHANNEL    C.FALLS    KERR_P
LD          Channel from Columbia Falls to Kerr Reservoir
PQ          MO=JAN        B=C.FALLS          C=FLOW-PNLTY_EDT E=JAN F=
PQ          MO=FEB E=FEB
PQ          MO=MAR E=MAR
PQ          MO=APR E=APR
PQ          MO=MAY E=MAY
PQ          MO=JUN E=JUN
PQ          MO=JUL E=JUL
PQ          MO=AUG E=AUG
PQ          MO=SEP E=SEP
PQ          MO=OCT E=OCT
PQ          MO=NOV E=NOV
PQ          MO=DEC E=DEC


LINK        INFLOW    S_SOURCE  KERR_P     1.0        0.0
LD          Inflow to Kerr Reservoir (Flathead Lake)
IN           B=KERR_P C=FLOW_LOC E=1MON F=INC-NAT80
```

```
..              Operational Full Pool is 1791 KAF, 1821.4 is Historic Storage Maximum
..              Historic Max Flow Coincident with Max Stor is 58,800 CFS
LINK            RSTORAGE   KERR_P     KERR_P    1.0         0.0        572.3      9999.0
LD              Storage in Kerr Reservoir
PS              MO=JAN         B=KERR_P C=STOR-PNLTY_EDT   E=JAN F=
PS              MO=FEB E=FEB
PS              MO=MAR E=MAR
PS              MO=APR E=APR
PS              MO=MAY E=MAY
PS              MO=JUN E=JUN
PS              MO=JUL E=JUL
PS              MO=AUG E=AUG
PS              MO=SEP E=SEP
PS              MO=OCT E=OCT
PS              MO=NOV E=NOV
PS              MO=DEC E=DEC

LINK            HREL       KERR_P     KERR
LD              Power Release from Kerr Reservoir
PQ              MO=JAN-DEC B=KERR_P       C=FLOW-PNLTY_HPE E=JAN F=HY-CAP

..              Limit Flow from Kerr to 55,000 CFS (3316.0 KAF/MO.)
LINK            RRELEASE   KERR       THOMPSON_P              90.6       3316.0
LD              Other Releases from Kerr Reservoir to Thompson Falls, Noxon, Cabinet
PQ              MO=JAN         B=KERR_P           C=FLOW-PNLTY_EDT E=JAN F=
PQ              MO=FEB E=FEB
PQ              MO=MAR E=MAR
PQ              MO=APR E=APR
PQ              MO=MAY E=MAY
PQ              MO=JUN E=JUN
PQ              MO=JUL E=JUL
PQ              MO=AUG E=AUG
PQ              MO=SEP E=SEP
PQ              MO=OCT E=OCT
PQ              MO=NOV E=NOV
PQ              MO=DEC E=DEC

LINK            INFLOW     S_SOURCE THOMPSON_P1.0        0.0
LD              Inflow to Thompson/Noxon/Cabinet
IN               B=THOMPSON_P C=FLOW_LOC E=1MON F=INC-NAT80

LINK            RSTORAGE   THOMPSON_PTHOMPSON_P1.0        0.0        999.0      999.0
LD              Storage in Thompson/Noxon/Cabinet Reservoir
PS              MO=JAN-DEC    B=THOMPSON_P C=STOR-PNLTY_EDT   E=JAN F=ZERO

LINK            HREL       THOMPSON_PTHOMPSON
LD              Power Release from Thompson/Noxon/Cabinet Reservoir
PQ              MO=JAN-DEC B=THOMPSON_P              C=FLOW-PNLTY_HPE E=JAN F=HY-CAP

LINK            RRELEASE   THOMPSON   ALBENI_P
LD              Channel from Cabinet to Albeni Falls, Box Canyon, & Boundary Res
PQ              MO=JAN-DEC    B=THOMPSON_P           C=FLOW-PNLTY_EDT E=JAN F=ZERO

LINK            INFLOW     S_SOURCE ALBENI_P  1.0        0.0
LD              Inflow to Albeni Falls, Box Canyon & Boundary Res
IN               B=ALBENI_P  C=FLOW_LOC E=1MON F=INC-NAT80

..              Operational Full Pool is 1652.5 KAF, 2084.4 is Historic Storage Maximu
..              Historic Max Flow Coincident with Max Stor is 145,000 CFS (8743 KAF)
LINK            RSTORAGE   ALBENI_P   ALBENI_P  1.0         0.0        446.4      9999.0
LD              Storage in Albeni Falls, Box Canyon and Boundary Res
PS              MO=JAN         B=ALBENI_P C=STOR-PNLTY_EDT   E=JAN F=
PS              MO=FEB E=FEB
PS              MO=MAR E=MAR
PS              MO=APR E=APR
PS              MO=MAY E=MAY
PS              MO=JUN E=JUN
PS              MO=JUL E=JUL
PS              MO=AUG E=AUG
PS              MO=SEP E=SEP
PS              MO=OCT E=OCT
PS              MO=NOV E=NOV
PS              MO=DEC E=DEC
```

```
LINK        HREL        ALBENI_P  ALBENI
LD          Power Release from Albeni Reservoir
PQ          MO=JAN-DEC B=ALBENI_P        C=FLOW-PNLTY_HPE E=JAN F=HY-CAP

..          Limit Flow from Albeni to 130,000 CFS (7839 KAF/MO.)
LINK        RRELEASE  ALBENI    COULEE_P                          7839.0
LD          Other Releases from Albeni/Box Canyon/Boundary Res. to Grand Coulee
PQ          MO=JAN        B=ALBENI_P        C=FLOW-PNLTY_EDT E=JAN F=
PQ          MO=FEB E=FEB
PQ          MO=MAR E=MAR
PQ          MO=APR E=APR
PQ          MO=MAY E=MAY
PQ          MO=JUN E=JUN
PQ          MO=JUL E=JUL
PQ          MO=AUG E=AUG
PQ          MO=SEP E=SEP
PQ          MO=OCT E=OCT
PQ          MO=NOV E=NOV
PQ          MO=DEC E=DEC

LINK        INFLOW    S_SOURCE  LIBBY_P    1.0        0.0
LD          Inflow to Libby Reservoir
IN           B=LIBBY_P C=FLOW_LOC E=1MON F=INC-NAT80

LINK        RSTORAGE  LIBBY_P    LIBBY_P   1.0        0.0       889.9     5869.4
LD          Storage in Libby Reservoir
PS          MO=JAN        B=LIBBY_P C=STOR-PNLTY_EDT   E=JAN F=
PS          MO=FEB E=FEB
PS          MO=MAR E=MAR
PS          MO=APR E=APR
PS          MO=MAY E=MAY
PS          MO=JUN E=JUN
PS          MO=JUL E=JUL
PS          MO=AUG E=AUG
PS          MO=SEP E=SEP
PS          MO=OCT E=OCT
PS          MO=NOV E=NOV
PS          MO=DEC E=DEC

LINK        HREL        LIBBY_P    LIBBY
LD          Power Release from Libby Reservoir
PQ          MO=JAN-DEC B=LIBBY_P        C=FLOW-PNLTY_HPE E=JAN F=HY-CAP

LINK        RRELEASE  LIBBY     BONNERS                          181.1
LD          Other Releases from Libby Reservoir to Bonners Ferry
PQ          MO=JAN        B=LIBBY_P        C=FLOW-PNLTY_EDT E=JAN F=
PQ          MO=FEB E=FEB
PQ          MO=MAR E=MAR
PQ          MO=APR E=APR
PQ          MO=MAY E=MAY
PQ          MO=JUN E=JUN
PQ          MO=JUL E=JUL
PQ          MO=AUG E=AUG
PQ          MO=SEP E=SEP
PQ          MO=OCT E=OCT
PQ          MO=NOV E=NOV
PQ          MO=DEC E=DEC

LINK        INFLOW    S_SOURCE  BONNERS   1.0        0.0
LD          Inflow to Bonners Ferry
IN           B=BONNERS C=FLOW_LOC E=1MON F=INC-NAT80
```

```
LINK        CHANNEL   BONNERS   CORRA.L_P
LD          Channel from Bonners Ferry to Corra Linn
PQ          MO=JAN        B=BONNERS          C=FLOW-PNLTY_EDT E=JAN F=
PQ          MO=FEB E=FEB
PQ          MO=MAR E=MAR
PQ          MO=APR E=APR
PQ          MO=MAY E=MAY
PQ          MO=JUN E=JUN
PQ          MO=JUL E=JUL
PQ          MO=AUG E=AUG
PQ          MO=SEP E=SEP
PQ          MO=OCT E=OCT
PQ          MO=NOV E=NOV
PQ          MO=DEC E=DEC


LINK        INFLOW    S_SOURCE  DUNCAN     1.0        0.0
LD          Inflow to Duncan Reservoir
IN          B=DUNCAN C=FLOW_LOC E=1MON F=INC-NAT80


LINK        RSTORAGE  DUNCAN    DUNCAN     1.0        0.0        30.0        1398.6
LD          Storage in Duncan Reservoir
PS          MO=JAN-DEC     B=DUNCAN    C=STOR-PNLTY_EDT   E=JAN   F=ZERO


..          Since there are no penalty functions for Duncan specify minimum flow
..          Minimum Release from Duncan is 100 cfs (6.0 KAF)
LINK        RRELEASE  DUNCAN    CORRA.L_P                          6.0
LD          Other Releases from Duncan to Corra.L
PQ          MO=JAN-DEC     B=DUNCAN              C=FLOW-PNLTY_EDT E=JAN F=Q_RESTRICT


LINK        INFLOW    S_SOURCE  CORRA.L_P 1.0        0.0
LD          Inflow to Corra Linn Reservoir
IN          B=CORRA.L_P C=FLOW_LOC E=1MON F=INC-NAT80


..          Operational Full Pool is 817 KAF, 2200 is Historic Storage Maximum
..          Historic Max Flow Coincident with Max Stor is 56,000 CFS  (3377KAF)
LINK        RSTORAGE  CORRA.L_P CORRA.L_P 1.0        0.0        144.0       9999.0
LD          Storage in Corra Linn Reservoir
PS          MO=JAN        B=CORRA.L_P C=STOR-PNLTY_EDT   E=JAN F=IJC-RULE.C
PS          MO=FEB E=FEB
PS          MO=MAR E=MAR
PS          MO=APR E=AUG
PS          MO=MAY E=AUG
PS          MO=JUN E=AUG
PS          MO=JUL E=AUG
PS          MO=AUG E=AUG
PS          MO=SEP E=DEC
PS          MO=OCT E=DEC
PS          MO=NOV E=DEC
PS          MO=DEC E=DEC


LINK        HREL          CORRA.L_P CORRA.L                                  3377.0
LD          Power Release from Corra Linn Reservoir
..          PQ         MO=JAN-DEC B=CORRA.L_P          C=FLOW-PNLTY_HPE E= F=Q_RESTR
PQ          MO=JAN-DEC     B=CORRA.L_P        C=FLOW-PNLTY_HPE E=JAN F=ZERO


..          Limit Flow from Corra Linn to 56,000 CFS (3377.0 KAF/MO.)
..          Relaxed Max Flow Limit to 9999 to Solve Infeasibility Problem???
LINK        RRELEASE  CORRA.L    COULEE_P
LD          Other Releases from Corra Linn Reservoir to Grand Coulee, Chief Joe
PQ          MO=JAN-DEC     B=CORRA.L_P        C=FLOW-PNLTY_EDT E=JAN F=ZERO


LINK        INFLOW    S_SOURCE  COULEE_P  1.0        0.0
LD          Diversion from Grande Coulee to Banks Lake (Negative inflows)
IN          B=COULEE_P C=FLOW_LOC E=1MON F=1980 LEVEL PUMPING


LINK        INFLOW    S_SOURCE  COULEE_P  1.0        0.0
LD          Inflow to Grand Coulee, Chief Joe
IN          B=COULEE_P  C=FLOW_LOC E=1MON F=INC-NAT80
```

```
LINK        RSTORAGE  COULEE_P  COULEE_P  1.0        0.0        3879.0      9107.0
LD          Storage in Grand Coulee
PS          MO=JAN        B=COULEE_P C=STOR-PNLTY_EDT   E=JAN F=
PS          MO=FEB E=FEB
PS          MO=MAR E=MAR
PS          MO=APR E=APR
PS          MO=MAY E=MAY
PS          MO=JUN E=JUN
PS          MO=JUL E=JUL
PS          MO=AUG E=AUG
PS          MO=SEP E=SEP
PS          MO=OCT E=OCT
PS          MO=NOV E=NOV
PS          MO=DEC E=DEC


LINK        HREL       COULEE_P  COULEE
LD          Power Release from Grande Coulee Reservoir
PQ          MO=JAN-DEC B=COULEE_P       C=FLOW-PNLTY_HPE E=JAN F=HY-CAP


LINK        RRELEASE  COULEE    WELLS_P
LD          Other Releases from Grand Coulee+Chief Joseph to Wells
PQ          MO=JAN-DEC  B=COULEE_P       C=FLOW-PNLTY_EDT E=JAN F=ZERO


LINK        INFLOW    S_SOURCE  WELLS_P   1.0        0.0
LD          Inflow to Wells
IN          B=WELLS_P C=FLOW_LOC E=1MON F=INC-NAT80


LINK        RSTORAGE  WELLS_P    WELLS_P   1.0        0.0        999.0       999.0
LD          Storage in Wells Reservoir
PS          MO=JAN-DEC    B=WELLS_P C=STOR-PNLTY_EDT   E=JAN F=ZERO


LINK        HREL       WELLS_P    WELLS
LD          Power Release from Wells Reservoir
PQ          MO=JAN-DEC B=WELLS_P       C=FLOW-PNLTY_HPE E=JAN F=HY-CAP


LINK        RRELEASE  WELLS     ROCKY.R_P
LD          Channel from Wells to Rocky Reach
PQ          MO=JAN-DEC  B=WELLS_P         C=FLOW-PNLTY_EDT E=JAN F=ZERO


LINK        INFLOW    S_SOURCE  ROCKY.R_P 1.0        0.0
LD          Inflow to Rocky Reach
IN          B=ROCKY.R_P C=FLOW_LOC E=1MON F=INC-NAT80


LINK        RSTORAGE  ROCKY.R_P ROCKY.R_P 1.0        0.0        999.0       999.0
LD          Storage in Rocky Reach Reservoir
PS          MO=JAN-DEC    B=ROCKY.R_P C=STOR-PNLTY_EDT   E=JAN F=ZERO


LINK        HREL       ROCKY.R_P ROCKY.R
LD          Power Release from Rocky Reach
PQ          MO=JAN-DEC B=ROCKY.R_P       C=FLOW-PNLTY_HPE E=JAN F=HY-CAP


LINK        RRELEASE  ROCKY.R    ROCK.IS_P
LD          Channel from Rocky Reach to Rock Island, Wanapum & Priest Rapids
PQ          MO=JAN-DEC    B=ROCKY.R_P         C=FLOW-PNLTY_EDT E=JAN F=ZERO


LINK        INFLOW    S_SOURCE  ROCK.IS_P   1.0        0.0
LD          Inflow to Rock Island, Wanapum & Priest Rapids Reservoirs
IN          B=ROCK.IS_P C=FLOW_LOC E=1MON F=INC-NAT80


LINK        RSTORAGE  ROCK.IS_P ROCK.IS_P 1.0        0.0        999.0       999.0
LD          Storage in Rock Island Reservoir
PS          MO=JAN-DEC    B=ROCK.IS_P C=STOR-PNLTY_EDT   E=JAN F=ZERO


LINK        HREL       ROCK.IS_P ROCK.IS
LD          Power Release from Rocky Island
PQ          MO=JAN-DEC B=ROCK.IS_P       C=FLOW-PNLTY_HPE E=JAN F=HY-CAP


LINK        RRELEASE  ROCK.IS    MCNARY_P
LD          Channel from Rock Island, Wanapum, &Priest Rapids to Mc Nary
PQ          MO=JAN-DEC  B=ROCK.IS_P         C=FLOW-PNLTY_EDT E=JAN F=ZERO
```

```
LINK        INFLOW    S_SOURCE  DWORSHAK_P  1.0        0.0
LD          Inflow to Dworshak Reservoir
IN          B=DWORSHAK_P C=FLOW_LOC E=1MON F=INC-NAT80

LINK        RSTORAGE  DWORSHAK_PDWORSHAK_P1.0        0.0        1452.2     3468.0
LD          Storage in Dworshak Reservoir
PS          MO=JAN        B=DWORSHAK_P C=STOR-PNLTY_EDT   E=JAN F=
PS          MO=FEB E=FEB
PS          MO=MAR E=MAR
PS          MO=APR E=APR
PS          MO=MAY E=MAY
PS          MO=JUN E=JUN
PS          MO=JUL E=JUL
PS          MO=AUG E=AUG
PS          MO=SEP E=SEP
PS          MO=OCT E=OCT
PS          MO=NOV E=NOV
PS          MO=DEC E=DEC

LINK        HREL      DWORSHAK_PDWORSHAK
LD          Power Release from Dworshak Reservoir
PQ          MO=JAN-DEC B=DWORSHAK_P        C=FLOW-PNLTY_HPE E=JAN F=HY-CAP

LINK        RRELEASE  DWORSHAK   SPALDING                60.4
LD          Other Releases from Dworshak Reservoir to Spalding
PQ          MO=JAN-DEC    B=DWORSHAK_P        C=FLOW-PNLTY_EDT E=JAN F=ZERO

LINK        INFLOW    S_SOURCE   SPALDING  1.0        0.0
LD          Inflow to Spalding
IN          B=SPALDING C=FLOW_LOC E=1MON F=INC-NAT80

LINK        CHANNEL   SPALDING   GRANITE_P
LD          Channel from Spalding to Granite/Goose/Monumental/Ice Harbor
PQ          MO=JAN        B=SPALDING        C=FLOW-PNLTY_EDT E=JAN F=
PQ          MO=FEB E=FEB
PQ          MO=MAR E=MAR
PQ          MO=APR E=APR
PQ          MO=MAY E=MAY
PQ          MO=JUN E=JUN
PQ          MO=JUL E=JUL
PQ          MO=AUG E=AUG
PQ          MO=SEP E=SEP
PQ          MO=OCT E=OCT
PQ          MO=NOV E=NOV
PQ          MO=DEC E=DEC

LINK        INFLOW    S_SOURCE   BROWNLEE_P1.0        0.0
LD          Inflow to Brownlee, Oxbow & Hells Canyon Reservoirs
IN          B=BROWNLEE_P C=FLOW_LOC E=1MON F=INC-NAT80

LINK        RSTORAGE  BROWNLEE_PBROWNLEE_P1.0        0.0        431.7     1426.7
LD          Storage in Brownlee, Oxbow & Hells Canyon Reservoirs
PS          MO=JAN-DEC    B=BROWNLEE_P C=STOR-PNLTY_EDT   E=JAN F=ZERO

LINK        HREL      BROWNLEE_PBROWNLEE
LD          Power Release from Brownlee Reservoir
PQ          MO=JAN-DEC B=BROWNLEE_P        C=FLOW-PNLTY_HPE E=JAN F=HY-CAP

LINK        RRELEASE  BROWNLEE   GRANITE_P               301.9
LD          Other Releases from Brownlee/Oxbow/Hells Canyon to Granite/...
PQ          MO=JAN-DEC    B=BROWNLEE_P        C=FLOW-PNLTY_EDT E=JAN F=ZERO

LINK        INFLOW    S_SOURCE   GRANITE_P  1.0        0.0
LD          Inflow to Lower Granite thru Ice Harbor Reservoirs
IN          B=GRANITE_P  C=FLOW_LOC E=1MON F=INC-NAT80
```

```
..              Lower limit = 144.0 based on Run-of-River conditions (Four Reservoirs)
LINK        RSTORAGE   GRANITE_P GRANITE_P 1.0                          144.0     1825.0
LD          Storage in Granite Reservoir
PS          MO=JAN          B=GRANITE_P C=STOR-PNLTY_EDT   E=JAN   F=
PS          MO=FEB E=FEB
PS          MO=MAR E=MAR
PS          MO=APR E=APR
PS          MO=MAY E=MAY
PS          MO=JUN E=JUN
PS          MO=JUL E=JUL
PS          MO=AUG E=AUG
PS          MO=SEP E=SEP
PS          MO=OCT E=OCT
PS          MO=NOV E=NOV
PS          MO=DEC E=DEC

LINK        HREL       GRANITE_P GRANITE
LD          Power Release from Granite Reservoir
PQ          MO=JAN-DEC B=GRANITE_P        C=FLOW-PNLTY_HPE E=JAN F=HY-CAP

LINK        RRELEASE   GRANITE   MCNARY_P
LD          Release from Granite/Goose/Monumental/Ice Harbor to McNary Reservoir
PQ          MO=JAN          B=GRANITE_P        C=FLOW-PNLTY_EDT E=JAN F=
PQ          MO=FEB E=FEB
PQ          MO=MAR E=MAR
PQ          MO=APR E=APR
PQ          MO=MAY E=MAY
PQ          MO=JUN E=JUN
PQ          MO=JUL E=JUL
PQ          MO=AUG E=AUG
PQ          MO=SEP E=SEP
PQ          MO=OCT E=OCT
PQ          MO=NOV E=NOV
PQ          MO=DEC E=DEC

LINK        INFLOW     S_SOURCE  MCNARY_P 1.0         0.0
LD          Inflow to Mc Nary Reservoir
IN          B=MCNARY_P C=FLOW_LOC E=1MON F=INC-NAT80

LINK        RSTORAGE   MCNARY_P  MCNARY_P 1.0                        1170.0     1350.0
LD          Storage in Mc Nary Reservoir
PS          MO=JAN          B=MCNARY_P C=STOR-PNLTY_EDT   E=JAN F=
PS          MO=FEB E=FEB
PS          MO=MAR E=MAR
PS          MO=APR E=APR
PS          MO=MAY E=MAY
PS          MO=JUN E=JUN
PS          MO=JUL E=JUL
PS          MO=AUG E=AUG
PS          MO=SEP E=SEP
PS          MO=OCT E=OCT
PS          MO=NOV E=NOV
PS          MO=DEC E=DEC

LINK        HREL       MCNARY_P  MCNARY
LD          Power Release from McNary Reservoir
PQ          MO=JAN-DEC B=MCNARY_P        C=FLOW-PNLTY_HPE E=JAN F=HY-CAP

LINK        RRELEASE   MCNARY    J.DAY_P
LD          Channel from Mc Nary to John Day
PQ          MO=JAN-DEC    B=MCNARY_P        C=FLOW-PNLTY_EDT E=JAN F=ZERO

LINK        INFLOW     S_SOURCE  J.DAY_P  1.0         0.0
LD          Inflow to John Day
IN          B=J.DAY_P C=FLOW_LOC E=1MON F=INC-NAT80
```

```
LINK      RSTORAGE  J.DAY_P    J.DAY_P    1.0                    1989.0    2523.0
LD        Storage in John Day Reservoir
PS        MO=JAN          B=J.DAY_P  C=STOR-PNLTY_EDT   E=JAN  F=
PS        MO=FEB E=FEB
PS        MO=MAR E=MAR
PS        MO=APR E=APR
PS        MO=MAY E=MAY
PS        MO=JUN E=JUN
PS        MO=JUL E=JUL
PS        MO=AUG E=AUG
PS        MO=SEP E=SEP
PS        MO=OCT E=OCT
PS        MO=NOV E=NOV
PS        MO=DEC E=DEC

LINK      HREL       J.DAY_P    J.DAY
LD        Power Release from John Day Reservoir
PQ        MO=JAN-DEC B=J.DAY_P       C=FLOW-PNLTY_HPE E=JAN F=HY-CAP

LINK      RRELEASE  J.DAY      DALLES_P
LD        Release from John Day to the Dalles & Bonneville Reservoirs
PQ        MO=JAN-DEC    B=J.DAY_P        C=FLOW-PNLTY_EDT E=JAN F=ZERO

LINK      INFLOW    S_SOURCE  DALLES_P   1.0        0.0
LD        Inflow to The Dalles & Bonneville Reservoirs
IN        B=DALLES_P  C=FLOW_LOC E=1MON F=INC-NAT80

LINK      RSTORAGE  DALLES_P  DALLES_P   1.0        0.0        999.0      999.0
LD        Storage in The Dalles and Bonneville Reservoirs
PS        MO=JAN-DEC    B=DALLES_P C=STOR-PNLTY_EDT   E=JAN F=ZERO

LINK      HREL       DALLES_P  DALLES
LD        Power Release from The Dalles
PQ        MO=JAN-DEC B=DALLES_P           C=FLOW-PNLTY_HPE E=JAN F=HY-CAP

LINK      RREL       DALLES     SINK
LD        Release from The Dalles & Bonneville to the Sink
PQ        MO=JAN          B=DALLES_P    C=FLOW-PNLTY_EDT E=JAN F=
PQ        MO=FEB E=FEB
PQ        MO=MAR E=MAR
PQ        MO=APR E=APR
PQ        MO=MAY E=MAY
PQ        MO=JUN E=JUN
PQ        MO=JUL E=JUL
PQ        MO=AUG E=AUG
PQ        MO=SEP E=SEP
PQ        MO=OCT E=OCT
PQ        MO=NOV E=NOV
PQ        MO=DEC E=DEC

STOP
```

Alternative 3: Operation with Additional Canadian Storage

HEC-PRM Input

```
..          ALT3
ZW          F=ALT3
..
..          50-Year Period of Analysis
..
..          ALTERNATIVE 3: OPTIMIZATION OF ALL US AND CANADIAN TREATY RESERVOIRS;
..            ADDITIONAL STORAGE IN MICA
..
..          1) MICA LIVE STORAGE IS 12,000,000 ACFT
..          2) CORRA LINN STORAGE PENALTIES ARE BASED ON IJC RULE CURVE
..          3) PUMPING FROM GRANDE COULEE TO THE COLUMBIA BASIN PROJECT
..             IS BASED ON 1980 LEVEL DATA
..          4) FLOW DATA ARE 1980 LEVEL OF DEVELOPMENT
..          5) PENALTY DATA ARE PHASE 1.5 WITH MODIFICATIONS
..
..          Non-Economic Penalty for Hydropower at Corra Linn to constrain Flow.
..          Duncan release penalty to constrain maximum flow to 20,000 cfs (1206ka
..
IDENT       S_SOURCE    SINK
TIME        JUL1928 JUN1978
..
J11.0E-05 1.0E+06          1.0       1.0           1         3
..
NODE        MICA_P        20075.0         0.1    20075.0
ND          Mica Reservoir Power Penalties
NODE        MICA
ND          Mica Reservoir Non-Power Penalties
NODE        ARROW          7327.0         0.1     7327.0
ND          Arrow Reservoir
NODE        H.HORSE_P      3647.1         0.1     3647.1
ND          Hungry Horse Reservoir Power Penalties
NODE        H.HORSE
ND          Hungry Horse Reservoir Non-Power Penalties
NODE        C.FALLS
ND          Columbia Falls
NODE        KERR_P         1791.0         0.1     1791.0
ND          Kerr Res-Flathead Lake Power Penalties
NODE        KERR
ND          Kerr Res-Flathead Lake Non-Power Penalties
NODE        THOMPSON_P      999.0         0.1      999.0
ND          Thompson Falls, Noxon and Cabinet Power Penalties
NODE        THOMPSON
ND          Thompson Falls, Noxon and Cabinet Non-Power Penalties
NODE        ALBENI_P       1586.7         0.1     1586.7
ND          Albeni Falls, Box Canyon and Boundary Power Penalties
NODE        ALBENI
ND          Albeni Falls, Box Canyon and Boundary Non-Power Penalties
NODE        LIBBY_P        5869.4         0.1     5869.4
ND          Libby Reservoir Power Penalties
NODE        LIBBY
ND          Libby Reservoir Non-Power Penalties
NODE        BONNERS
ND          Bonners Ferry
NODE        DUNCAN         1398.6         0.1     1398.6
ND          Duncan Reservoir
NODE        CORRA.L_P       570.0         0.1      570.0
ND          Corra Linn Power Penalties
NODE        CORRA.L
ND          Corra Linn Non-Power Penalties
NODE        COULEE_P       9107.0         0.1     9107.0
ND          Grand Coulee and Chief Joseph Power Penalties
NODE        COULEE
ND          Grand Coulee and Chief Joseph Non-Power Penalties
```

```
NODE        WELLS_P          999.0        0.1      999.0
ND          Wells Reservoir Power Penalties
NODE        WELLS
ND          Wells Reservoir Non-Power Penalties
NODE        ROCKY.R_P        999.0        0.1      999.0
ND          Rocky Reach Reservoir Power Penalties
NODE        ROCKY.R
ND          Rocky Reach Reservoir Non-Power Penalties

NODE        ROCK.IS_P        999.0        0.1      999.0
ND          Rock Island, Wanapum and Priest Rapids Power Penalties
NODE        ROCK.IS
ND          Rock Island, Wanapum and Priest Rapids Non-Power Penalties
NODE        DWORSHAK_P      3468.0        0.1     3468.0
ND          Dworshak Reservoir Power Penalties
NODE        DWORSHAK
ND          Dworshak Reservoir Non-Power Penalties
NODE        SPALDING
ND          Spalding
NODE        BROWNLEE_P      1426.7        0.1     1426.7
ND          Brownlee, Oxbow, and Hells Canyon Power Penalties
NODE        BROWNLEE
ND          Brownlee, Oxbow, and Hells Canyon Non-Power Penalties
NODE        GRANITE_P       1825.0        0.1     1825.0
ND          L.Granite\Little Goose\L.Monumental\Ice Harbor Power Penalties
NODE        GRANITE
ND          L.Granite\Little Goose\L.Monumental\Ice Harbor Non-Power Penalties
NODE        MCNARY_P        1350.0        0.1     1350.0
ND          Mc Nary Reservoir Power Penalties
NODE        MCNARY
ND          Mc Nary Reservoir Non-Power Penalties
NODE        J.DAY_P         2523.0        0.1     2523.0
ND          John Day Reservoir Power Penalties
NODE        J.DAY
ND          John Day Reservoir Non-Power Penalties
NODE        DALLES_P         999.0        0.1      999.0
ND          The Dalles and Bonneville Reservoirs Power Penalties
NODE        DALLES
ND          The Dalles and Bonneville Reservoirs Non-Power Penalties


LINK        DIVR      S_SOURCE   SINK       1.0        0.0
LD          Continuity Link

LINK        INFLOW    S_SOURCE   MICA_P     1.0        0.0
LD          Inflow to Mica Reservoir
IN          B=MICA_P   C=FLOW_LOC E=1MON F=INC-NAT80

..          12000 KAF ACTIVE STORAGE 7000 TREATY + 5000 NON-TREATY
LINK        RSTORAGE  MICA_P     MICA_P     1.0        0.0         8075.0     20075.
LD          Storage in Mica Reservoir
PS          MO=JAN-DEC    B=MICA_P   C=STOR-PNLTY_EDT   E=JAN   F=ZERO

LINK        HREL      MICA_P     MICA
LD          Power Release from Mica
PQ          MO=JAN-DEC    B=MICA_P       C=FLOW-PNLTY_HPE E=JAN F=ZERO

..          Since there are no penalty functions for Mica specify minimum flow
..          "Seasonal" Minimum Release from Mica of 10,000 cfs (603.7 KAF)
..          is represented by two seasonal flow penalty curves
LINK        RRELEASE  MICA       ARROW
LD          Other Releases from Mica to Arrow
PQ          MO=JAN        B=MICA_P       C=FLOW-PNLTY_EDT E=JAN F=
PQ          MO=FEB E=FEB
PQ          MO=MAR E=MAR
PQ          MO=APR E=APR
PQ          MO=MAY E=MAY
PQ          MO=JUN E=JUN
PQ          MO=JUL E=JUL
PQ          MO=AUG E=AUG
PQ          MO=SEP E=SEP
PQ          MO=OCT E=OCT
PQ          MO=NOV E=NOV
PQ          MO=DEC E=DEC
```

```
LINK        INFLOW    S_SOURCE  ARROW      1.0         0.0
LD          Inflow to Arrow Reservoir
IN          B=ARROW C=FLOW_LOC E=1MON F=INC-NAT80


LINK        RSTORAGE  ARROW         ARROW    1.0         0.0         227.0       7327.0
LD          Storage in Arrow Reservoir
PS          MO=JAN-DEC    B=ARROW     C=STOR-PNLTY_EDT   E=JAN   F=ZERO


..          Since there are no penalty functions for Arrow specify minimum flow
..          Minimum Release from Arrow is 5,000 cfs (301.9 KAF)
LINK        RRELEASE  ARROW       COULEE_P                       301.9
LD          Other Releases from Arrow to Coulee
PQ          MO=JAN-DEC    B=ARROW           C=FLOW-PNLTY_EDT E=JAN F=ZERO


LINK        INFLOW   S_SOURCE  H.HORSE_P 1.0         0.0
LD          Inflow to Hungry Horse Reservoir
IN          B=H.HORSE_P C=FLOW_LOC E=1MON F=INC-NAT80


LINK        RSTORAGE  H.HORSE_P H.HORSE_P 1.0         0.0         486.0       3647.1
LD          Storage in Hungry Horse Reservoir
PS          MO=JAN          B=H.HORSE_P  C=STOR-PNLTY_EDT   E=JAN   F=
PS          MO=FEB E=FEB
PS          MO=MAR E=MAR
PS          MO=APR E=APR
PS          MO=MAY E=MAY
PS          MO=JUN E=JUN
PS          MO=JUL E=JUL
PS          MO=AUG E=AUG
PS          MO=SEP E=SEP
PS          MO=OCT E=OCT
PS          MO=NOV E=NOV
PS          MO=DEC E=DEC


LINK        HREL      H.HORSE_P H.HORSE
LD          Power Release from Hungry Horse Reservoir
PQ          MO=JAN-FEB B=H.HORSE_P           C=FLOW-PNLTY_HPE E=DEC-FEB
PQ          MO=MAR      B=H.HORSE_P           C=FLOW-PNLTY_HPE E=MAR_NOV
PQ          MO=APR-MAY B=H.HORSE_P            C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ          MO=JUN-SEP B=H.HORSE_P            C=FLOW-PNLTY_HPE E=JUN-SEP
PQ          MO=OCT      B=H.HORSE_P           C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ          MO=NOV      B=H.HORSE_P           C=FLOW-PNLTY_HPE E=MAR_NOV
PQ          MO=DEC      B=H.HORSE_P           C=FLOW-PNLTY_HPE E=DEC-FEB


LINK        RRELEASE  H.HORSE   C.FALLS                        24.1
LD          Other Releases from Hungry Horse Reservoir to Columbia Falls
PQ          MO=JAN-DEC    B=H.HORSE_P         C=FLOW-PNLTY_EDT E=JAN F=ZERO


LINK        INFLOW    S_SOURCE  C.FALLS    1.0         0.0
LD          Inflow to Columbia Falls
IN           B=C.FALLS C=FLOW_LOC E=1MON F=INC-NAT80


LINK        CHANNEL   C.FALLS   KERR_P
LD          Channel from Columbia Falls to Kerr Reservoir
PQ          MO=JAN          B=C.FALLS         C=FLOW-PNLTY_EDT E=JAN F=
PQ          MO=FEB E=FEB
PQ          MO=MAR E=MAR
PQ          MO=APR E=APR
PQ          MO=MAY E=MAY
PQ          MO=JUN E=JUN
PQ          MO=JUL E=JUL
PQ          MO=AUG E=AUG
PQ          MO=SEP E=SEP
PQ          MO=OCT E=OCT
PQ          MO=NOV E=NOV
PQ          MO=DEC E=DEC


LINK        INFLOW    S_SOURCE  KERR_P     1.0         0.0
LD          Inflow to Kerr Reservoir (Flathead Lake)
IN           B=KERR_P C=FLOW_LOC E=1MON F=INC-NAT80
```

```
..              Operational Full Pool is 1791 KAF, 1821.4 is Historic Storage Maximum
..              Historic Max Flow Coincident with Max Stor is 58,800 CFS
LINK            RSTORAGE   KERR_P     KERR_P     1.0        0.0         572.3       9999.0
LD              Storage in Kerr Reservoir
PS              MO=JAN         B=KERR_P C=STOR-PNLTY_EDT   E=JAN F=
PS              MO=FEB E=FEB
PS              MO=MAR E=MAR
PS              MO=APR E=APR
PS              MO=MAY E=MAY
PS              MO=JUN E=JUN
PS              MO=JUL E=JUL
PS              MO=AUG E=AUG
PS              MO=SEP E=SEP
PS              MO=OCT E=OCT
PS              MO=NOV E=NOV
PS              MO=DEC E=DEC


LINK            HREL       KERR_P     KERR
LD              Power Release from Kerr Reservoir
PQ              MO=JAN-FEB B=KERR_P        C=FLOW-PNLTY_HPE E=DEC-FEB F=
PQ              MO=MAR     B=KERR_P        C=FLOW-PNLTY_HPE E=MAR_NOV
PQ              MO=APR-MAY B=KERR_P        C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ              MO=JUN-SEP B=KERR_P        C=FLOW-PNLTY_HPE E=JUN-SEP
PQ              MO=OCT     B=KERR_P        C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ              MO=NOV     B=KERR_P        C=FLOW-PNLTY_HPE E=MAR_NOV
PQ              MO=DEC     B=KERR_P        C=FLOW-PNLTY_HPE E=DEC-FEB


..              Limit Flow from Kerr to 55,000 CFS (3316.0 KAF/MO.)
LINK            RRELEASE   KERR       THOMPSON_P             90.6        3316.0
LD              Other Releases from Kerr Reservoir to Thompson Falls, Noxon, Cabinet
PQ              MO=JAN         B=KERR_P        C=FLOW-PNLTY_EDT E=JAN F=
PQ              MO=FEB E=FEB
PQ              MO=MAR E=MAR
PQ              MO=APR E=APR
PQ              MO=MAY E=MAY
PQ              MO=JUN E=JUN
PQ              MO=JUL E=JUL
PQ              MO=AUG E=AUG
PQ              MO=SEP E=SEP
PQ              MO=OCT E=OCT
PQ              MO=NOV E=NOV
PQ              MO=DEC E=DEC


LINK            INFLOW     S_SOURCE   THOMPSON_P1.0          0.0
LD              Inflow to Thompson/Noxon/Cabinet
IN               B=THOMPSON_P C=FLOW_LOC E=1MON F=INC-NAT80


LINK            RSTORAGE   THOMPSON_PTHOMPSON_P1.0          0.0         999.0       999.0
LD              Storage in Thompson/Noxon/Cabinet Reservoir
PS              MO=JAN-DEC    B=THOMPSON_P C=STOR-PNLTY_EDT   E=JAN F=ZERO


LINK            HREL       THOMPSON_PTHOMPSON
LD              Power Release from Thompson/Noxon/Cabinet Reservoir
PQ              MO=JAN-FEB B=THOMPSON_P        C=FLOW-PNLTY_HPE E=DEC-FEB F=
PQ              MO=MAR     B=THOMPSON_P        C=FLOW-PNLTY_HPE E=MAR_NOV
PQ              MO=APR-MAY B=THOMPSON_P        C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ              MO=JUN-SEP B=THOMPSON_P        C=FLOW-PNLTY_HPE E=JUN-SEP
PQ              MO=OCT     B=THOMPSON_P        C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ              MO=NOV     B=THOMPSON_P        C=FLOW-PNLTY_HPE E=MAR_NOV
PQ              MO=DEC     B=THOMPSON_P        C=FLOW-PNLTY_HPE E=DEC-FEB


LINK            RRELEASE   THOMPSON   ALBENI_P
LD              Channel from Cabinet to Albeni Falls, Box Canyon, & Boundary Res
PQ              MO=JAN-DEC    B=THOMPSON_P        C=FLOW-PNLTY_EDT E=JAN F=ZERO


LINK            INFLOW     S_SOURCE   ALBENI_P   1.0        0.0
LD              Inflow to Albeni Falls, Box Canyon & Boundary Res
IN               B=ALBENI_P   C=FLOW_LOC E=1MON F=INC-NAT80
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```
..              Operational Full Pool is 1652.5 KAF, 2084.4 is Historic Storage Maximu
..              Historic Max Flow Coincident with Max Stor is 145,000 CFS (8743 KAF)
LINK            RSTORAGE  ALBENI_P  ALBENI_P  1.0        0.0        446.4     9999.0
LD              Storage in Albeni Falls, Box Canyon and Boundary Res
PS              MO=JAN          B=ALBENI_P C=STOR-PNLTY_EDT  E=JAN F=
PS              MO=FEB E=FEB
PS              MO=MAR E=MAR
PS              MO=APR E=APR
PS              MO=MAY E=MAY
PS              MO=JUN E=JUN
PS              MO=JUL E=JUL
PS              MO=AUG E=AUG
PS              MO=SEP E=SEP
PS              MO=OCT E=OCT
PS              MO=NOV E=NOV
PS              MO=DEC E=DEC


LINK            HREL        ALBENI_P  ALBENI
LD              Power Release from Albeni Reservoir
PQ              MO=JAN-FEB B=ALBENI_P       C=FLOW-PNLTY_HPE E=DEC-FEB
PQ              MO=MAR     B=ALBENI_P       C=FLOW-PNLTY_HPE E=MAR_NOV
PQ              MO=APR-MAY B=ALBENI_P       C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ              MO=JUN-SEP B=ALBENI_P       C=FLOW-PNLTY_HPE E=JUN-SEP
PQ              MO=OCT     B=ALBENI_P       C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ              MO=NOV     B=ALBENI_P       C=FLOW-PNLTY_HPE E=MAR_NOV
PQ              MO=DEC     B=ALBENI_P       C=FLOW-PNLTY_HPE E=DEC-FEB


..              Limit Flow from Albeni to 130,000 CFS (7839 KAF/MO.)
LINK            RRELEASE  ALBENI    COULEE_P                          7839.0
LD              Other Releases from Albeni/Box Canyon/Boundary Res. to Grand Coulee
PQ              MO=JAN          B=ALBENI_P       C=FLOW-PNLTY_EDT E=JAN F=
PQ              MO=FEB E=FEB
PQ              MO=MAR E=MAR
PQ              MO=APR E=APR
PQ              MO=MAY E=MAY
PQ              MO=JUN E=JUN
PQ              MO=JUL E=JUL
PQ              MO=AUG E=AUG
PQ              MO=SEP E=SEP
PQ              MO=OCT E=OCT
PQ              MO=NOV E=NOV
PQ              MO=DEC E=DEC


LINK            INFLOW    S_SOURCE LIBBY_P    1.0        0.0
LD              Inflow to Libby Reservoir
IN               B=LIBBY_P C=FLOW_LOC E=1MON F=INC-NAT80


LINK            RSTORAGE  LIBBY_P   LIBBY_P    1.0        0.0        889.9     5869.4
LD              Storage in Libby Reservoir
PS              MO=JAN          B=LIBBY_P C=STOR-PNLTY_EDT  E=JAN F=
PS              MO=FEB E=FEB
PS              MO=MAR E=MAR
PS              MO=APR E=APR
PS              MO=MAY E=MAY
PS              MO=JUN E=JUN
PS              MO=JUL E=JUL
PS              MO=AUG E=AUG
PS              MO=SEP E=SEP
PS              MO=OCT E=OCT
PS              MO=NOV E=NOV
PS              MO=DEC E=DEC


LINK            HREL        LIBBY_P   LIBBY
LD              Power Release from Libby Reservoir
PQ              MO=JAN-FEB B=LIBBY_P        C=FLOW-PNLTY_HPE E=DEC-FEB
PQ              MO=MAR     B=LIBBY_P        C=FLOW-PNLTY_HPE E=MAR_NOV
PQ              MO=APR-MAY B=LIBBY_P        C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ              MO=JUN-SEP B=LIBBY_P        C=FLOW-PNLTY_HPE E=JUN-SEP
PQ              MO=OCT     B=LIBBY_P        C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ              MO=NOV     B=LIBBY_P        C=FLOW-PNLTY_HPE E=MAR_NOV
PQ              MO=DEC     B=LIBBY_P        C=FLOW-PNLTY_HPE E=DEC-FEB
```

```
LINK        RRELEASE  LIBBY      BONNERS                           181.1
LD          Other Releases from Libby Reservoir to Bonners Ferry
PQ          MO=JAN       B=LIBBY_P       C=FLOW-PNLTY_EDT E=JAN F=
PQ          MO=FEB E=FEB
PQ          MO=MAR E=MAR
PQ          MO=APR E=APR
PQ          MO=MAY E=MAY
PQ          MO=JUN E=JUN
PQ          MO=JUL E=JUL
PQ          MO=AUG E=AUG
PQ          MO=SEP E=SEP
PQ          MO=OCT E=OCT
PQ          MO=NOV E=NOV
PQ          MO=DEC E=DEC


LINK        INFLOW    S_SOURCE  BONNERS    1.0        0.0
LD          Inflow to Bonners Ferry
IN           B=BONNERS C=FLOW_LOC E=1MON F=INC-NAT80


LINK        CHANNEL   BONNERS    CORRA.L_P
LD          Channel from Bonners Ferry to Corra Linn
PQ          MO=JAN       B=BONNERS              C=FLOW-PNLTY_EDT E=JAN F=
PQ          MO=FEB E=FEB
PQ          MO=MAR E=MAR
PQ          MO=APR E=APR
PQ          MO=MAY E=MAY
PQ          MO=JUN E=JUN
PQ          MO=JUL E=JUL
PQ          MO=AUG E=AUG
PQ          MO=SEP E=SEP
PQ          MO=OCT E=OCT
PQ          MO=NOV E=NOV
PQ          MO=DEC E=DEC


LINK        INFLOW    S_SOURCE  DUNCAN     1.0        0.0
LD          Inflow to Duncan Reservoir
IN          B=DUNCAN C=FLOW_LOC E=1MON F=INC-NAT80


LINK        RSTORAGE  DUNCAN     DUNCAN     1.0        0.0        30.0      1398.6
LD          Storage in Duncan Reservoir
PS          MO=JAN-DEC      B=DUNCAN     C=STOR-PNLTY_EDT   E=JAN   F=ZERO


..          Since there are no penalty functions for Duncan specify minimum flow
..          Minimum Release from Duncan is 100 cfs (6.0 KAF)
LINK        RRELEASE  DUNCAN     CORRA.L_P                          6.0
LD          Other Releases from Duncan to Corra.L
PQ          MO=JAN-DEC      B=DUNCAN               C=FLOW-PNLTY_EDT E=JAN F=Q_RESTRICT


LINK        INFLOW    S_SOURCE  CORRA.L_P 1.0        0.0
LD          Inflow to Corra Linn Reservoir
IN           B=CORRA.L_P C=FLOW_LOC E=1MON F=INC-NAT80


..          Operational Full Pool is 817 KAF, 2200 is Historic Storage Maximum
..          Historic Max Flow Coincident with Max Stor is 56,000 CFS   (3377KAF)
LINK        RSTORAGE  CORRA.L_P CORRA.L_P 1.0        0.0        144.0      9999.0
LD          Storage in Corra Linn Reservoir
PS          MO=JAN       B=CORRA.L_P C=STOR-PNLTY_EDT   E=JAN F=IJC-RULE.C
PS          MO=FEB E=FEB
PS          MO=MAR E=MAR
PS          MO=APR E=AUG
PS          MO=MAY E=AUG
PS          MO=JUN E=AUG
PS          MO=JUL E=AUG
PS          MO=AUG E=AUG
PS          MO=SEP E=DEC
PS          MO=OCT E=DEC
PS          MO=NOV E=DEC
PS          MO=DEC E=DEC


LINK        HREL      CORRA.L_P CORRA.L                           3377.0
LD          Power Release from Corra Linn Reservoir
..          PQ          MO=JAN-DEC B=CORRA.L_P          C=FLOW-PNLTY_HPE E= F=Q_RESTR
PQ          MO=JAN-DEC      B=CORRA.L_P        C=FLOW-PNLTY_HPE E=JAN F=ZERO
```

```
  ..           Limit Flow from Corra Linn to 56,000 CFS (3377.0 KAF/MO.)
  ..           Relaxed Max Flow Limit to 9999 to Solve Infeasibility Problem???
LINK         RRELEASE   CORRA.L    COULEE_P
LD           Other Releases from Corra Linn Reservoir to Grand Coulee, Chief Joe
PQ           MO=JAN-DEC     B=CORRA.L_P         C=FLOW-PNLTY_EDT E=JAN F=ZERO


LINK         INFLOW    S_SOURCE   COULEE_P   1.0         0.0
LD           Diversion from Grande Coulee to Banks Lake (Negative inflows)
IN            B=COULEE_P C=FLOW_LOC E=1MON F=1980 LEVEL PUMPING


LINK         INFLOW    S_SOURCE   COULEE_P   1.0         0.0
LD           Inflow to Grand Coulee, Chief Joe
IN            B=COULEE_P  C=FLOW_LOC E=1MON F=INC-NAT80


LINK         RSTORAGE   COULEE_P   COULEE_P   1.0         0.0         3879.0     9107.0
LD           Storage in Grand Coulee
PS           MO=JAN          B=COULEE_P C=STOR-PNLTY_EDT   E=JAN F=
PS           MO=FEB E=FEB
PS           MO=MAR E=MAR
PS           MO=APR E=APR
PS           MO=MAY E=MAY
PS           MO=JUN E=JUN
PS           MO=JUL E=JUL
PS           MO=AUG E=AUG
PS           MO=SEP E=SEP
PS           MO=OCT E=OCT
PS           MO=NOV E=NOV
PS           MO=DEC E=DEC


LINK         HREL       COULEE_P   COULEE
LD           Power Release from Grande Coulee Reservoir
PQ           MO=JAN-FEB B=COULEE_P         C=FLOW-PNLTY_HPE E=DEC-FEB
PQ           MO=MAR     B=COULEE_P         C=FLOW-PNLTY_HPE E=MAR_NOV
PQ           MO=APR-MAY B=COULEE_P         C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ           MO=JUN-SEP B=COULEE_P         C=FLOW-PNLTY_HPE E=JUN-SEP
PQ           MO=OCT     B=COULEE_P         C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ           MO=NOV     B=COULEE_P         C=FLOW-PNLTY_HPE E=MAR_NOV
PQ           MO=DEC     B=COULEE_P         C=FLOW-PNLTY_HPE E=DEC-FEB


LINK         RRELEASE   COULEE     WELLS_P
LD           Other Releases from Grand Coulee+Chief Joseph to Wells
PQ           MO=JAN-DEC     B=COULEE_P         C=FLOW-PNLTY_EDT E=JAN F=ZERO


LINK         INFLOW    S_SOURCE   WELLS_P   1.0         0.0
LD           Inflow to Wells
IN           B=WELLS_P C=FLOW_LOC E=1MON F=INC-NAT80


LINK         RSTORAGE   WELLS_P    WELLS_P   1.0         0.0         999.0       999.0
LD           Storage in Wells Reservoir
PS           MO=JAN-DEC     B=WELLS_P C=STOR-PNLTY_EDT   E=JAN F=ZERO


LINK         HREL       WELLS_P    WELLS
LD           Power Release from Wells Reservoir
PQ           MO=JAN-FEB B=WELLS_P         C=FLOW-PNLTY_HPE E=DEC-FEB F=
PQ           MO=MAR     B=WELLS_P         C=FLOW-PNLTY_HPE E=MAR_NOV
PQ           MO=APR-MAY B=WELLS_P         C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ           MO=JUN-SEP B=WELLS_P         C=FLOW-PNLTY_HPE E=JUN-SEP
PQ           MO=OCT     B=WELLS_P         C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ           MO=NOV     B=WELLS_P         C=FLOW-PNLTY_HPE E=MAR_NOV
PQ           MO=DEC     B=WELLS_P         C=FLOW-PNLTY_HPE E=DEC-FEB


LINK         RRELEASE   WELLS      ROCKY.R_P
LD           Channel from Wells to Rocky Reach
PQ           MO=JAN-DEC     B=WELLS_P         C=FLOW-PNLTY_EDT E=JAN F=ZERO


LINK         INFLOW    S_SOURCE   ROCKY.R_P 1.0         0.0
LD           Inflow to Rocky Reach
IN           B=ROCKY.R_P C=FLOW_LOC E=1MON F=INC-NAT80


LINK         RSTORAGE   ROCKY.R_P ROCKY.R_P 1.0         0.0         999.0       999.0
LD           Storage in Rocky Reach Reservoir
PS           MO=JAN-DEC     B=ROCKY.R_P C=STOR-PNLTY_EDT   E=JAN F=ZERO
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LINK        HREL        ROCKY.R_P ROCKY.R
LD          Power Release from Rocky Reach
PQ          MO=JAN-FEB B=ROCKY.R_P        C=FLOW-PNLTY_HPE E=DEC-FEB F=
PQ          MO=MAR      B=ROCKY.R_P        C=FLOW-PNLTY_HPE E=MAR_NOV
PQ          MO=APR-MAY B=ROCKY.R_P        C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ          MO=JUN-SEP B=ROCKY.R_P        C=FLOW-PNLTY_HPE E=JUN-SEP
PQ          MO=OCT      B=ROCKY.R_P        C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ          MO=NOV      B=ROCKY.R_P        C=FLOW-PNLTY_HPE E=MAR_NOV
PQ          MO=DEC      B=ROCKY.R_P        C=FLOW-PNLTY_HPE E=DEC-FEB

LINK        RRELEASE ROCKY.R    ROCK.IS_P
LD          Channel from Rocky Reach to Rock Island, Wanapum & Priest Rapids
PQ          MO=JAN-DEC    B=ROCKY.R_P           C=FLOW--PNLTY_EDT E=JAN F=ZERO

LINK        INFLOW    S_SOURCE  ROCK.IS_P   1.0        0.0
LD          Inflow to Rock Island, Wanapum & Priest Rapids Reservoirs
IN          B=ROCK.IS_P C=FLOW_LOC E=1MON F=INC-NAT80

LINK        RSTORAGE  ROCK.IS_P ROCK.IS_P 1.0         0.0         999.0        999.0
LD          Storage in Rock Island Reservoir
PS          MO=JAN-DEC    B=ROCK.IS_P C=STOR-PNLTY_EDT  E=JAN F=ZERO

LINK        HREL        ROCK.IS_P ROCK.IS
LD          Power Release from Rocky Island
PQ          MO=JAN-FEB B=ROCK.IS_P        C=FLOW-PNLTY_HPE E=DEC-FEB F=
PQ          MO=MAR      B=ROCK.IS_P        C=FLOW-PNLTY_HPE E=MAR_NOV
PQ          MO=APR-MAY B=ROCK.IS_P        C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ          MO=JUN-SEP B=ROCK.IS_P·       C=FLOW-PNLTY_HPE E=JUN-SEP
PQ          MO=OCT      B=ROCK.IS_P        C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ          MO=NOV      B=ROCK.IS_P        C=FLOW-PNLTY_HPE E=MAR_NOV
PQ          MO=DEC      B=ROCK.IS_P        C=FLOW-PNLTY_HPE E=DEC-FEB

LINK        RRELEASE  ROCK.IS    MCNARY_P
LD          Channel from Rock Island, Wanapum, &Priest Rapids to Mc Nary
PQ          MO=JAN-DEC    B=ROCK.IS_P           C=FLOW-PNLTY_EDT E=JAN F=ZERO

LINK        INFLOW    S_SOURCE   DWORSHAK_P   1.0        0.0
LD          Inflow to Dworshak Reservoir
IN          B=DWORSHAK_P C=FLOW_LOC E=1MON F=INC-NAT80

LINK        RSTORAGE   DWORSHAK_PDWORSHAK_P1.0         0.0         1452.2        3468.0
LD          Storage in Dworshak Reservoir
PS          MO=JAN        B=DWORSHAK_P C=STOR-PNLTY_EDT   E=JAN F=
PS          MO=FEB E=FEB
PS          MO=MAR E=MAR
PS          MO=APR E=APR
PS          MO=MAY E=MAY
PS          MO=JUN E=JUN
PS          MO=JUL E=JUL
PS          MO=AUG E=AUG
PS          MO=SEP E=SEP
PS          MO=OCT E=OCT
PS          MO=NOV E=NOV
PS          MO=DEC E=DEC

LINK        HREL        DWORSHAK_PDWORSHAK
LD          Power Release from Dworshak Reservoir
PQ          MO=JAN-FEB B=DWORSHAK_P        C=FLOW-PNLTY_HPE E=DEC-FEB
PQ          MO=MAR      B=DWORSHAK_P        C=FLOW-PNLTY_HPE E=MAR_NOV
PQ          MO=APR-MAY B=DWORSHAK_P        C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ          MO=JUN-SEP B=DWORSHAK_P        C=FLOW-PNLTY_HPE E=JUN-SEP
PQ          MO=OCT      B=DWORSHAK_P        C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ          MO=NOV      B=DWORSHAK_P        C=FLOW-PNLTY_HPE E=MAR_NOV
PQ          MO=DEC      B=DWORSHAK_P        C=FLOW-PNLTY_HPE E=DEC-FEB

LINK        RRELEASE  DWORSHAK    SPALDING                        60.4
LD          Other Releases from Dworshak Reservoir to Spalding
PQ          MO=JAN-DEC    B=DWORSHAK_P           C=FLOW-PNLTY_EDT E=JAN F=ZERO

LINK        INFLOW    S_SOURCE   SPALDING  1.0        0.0
LD          Inflow to Spalding
IN          B=SPALDING C=FLOW_LOC E=1MON F=INC-NAT80
```

```
LINK        CHANNEL   SPALDING  GRANITE_P
LD          Channel from Spalding to Granite/Goose/Monumental/Ice Harbor
PQ          MO=JAN        B=SPALDING          C=FLOW-PNLTY_EDT E=JAN F=
PQ          MO=FEB E=FEB
PQ          MO=MAR E=MAR
PQ          MO=APR E=APR
PQ          MO=MAY E=MAY
PQ          MO=JUN E=JUN
PQ          MO=JUL E=JUL
PQ          MO=AUG E=AUG
PQ          MO=SEP E=SEP
PQ          MO=OCT E=OCT
PQ          MO=NOV E=NOV
PQ          MO=DEC E=DEC


LINK        INFLOW    S_SOURCE  BROWNLEE_P1.0        0.0
LD          Inflow to Brownlee, Oxbow & Hells Canyon Reservoirs
IN          B=BROWNLEE_P C=FLOW_LOC E=1MON F=INC-NAT80


LINK        RSTORAGE  BROWNLEE_PBROWNLEE_P1.0       0.0        431.7      1426.7
LD          Storage in Brownlee, Oxbow & Hells Canyon Reservoirs
PS          MO=JAN-DEC    B=BROWNLEE_P C=STOR-PNLTY_EDT   E=JAN F=ZERO


LINK        HREL      BROWNLEE_PBROWNLEE
LD          Power Release from Brownlee Reservoir
PQ          MO=JAN-FEB B=BROWNLEE_P          C=FLOW-PNLTY_HPE E=DEC-FEB F=
PQ          MO=MAR     B=BROWNLEE_P          C=FLOW-PNLTY_HPE E=MAR_NOV
PQ          MO=APR-MAY B=BROWNLEE_P          C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ          MO=JUN-SEP B=BROWNLEE_P          C=FLOW-PNLTY_HPE E=JUN-SEP
PQ          MO=OCT     B=BROWNLEE_P          C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ          MO=NOV     B=BROWNLEE_P          C=FLOW-PNLTY_HPE E=MAR_NOV
PQ          MO=DEC     B=BROWNLEE_P          C=FLOW-PNLTY_HPE E=DEC-FEB


LINK        RRELEASE  BROWNLEE  GRANITE_P                    301.9
LD          Other Releases from Brownlee/Oxbow/Hells Canyon to Granite/...
PQ          MO=JAN-DEC    B=BROWNLEE_P        C=FLOW-PNLTY_EDT E=JAN F=ZERO


LINK        INFLOW    S_SOURCE  GRANITE_P 1.0        0.0
LD          Inflow to Lower Granite thru Ice Harbor Reservoirs
IN          B=GRANITE_P   C=FLOW_LOC E=1MON F=INC-NAT80


..          Lower limit = 144.0 based on Run-of-River conditions (Four Reservoirs)
LINK        RSTORAGE  GRANITE_P GRANITE_P 1.0                144.0    1825.0
LD          Storage in Granite Reservoir
PS          MO=JAN        B=GRANITE_P C=STOR-PNLTY_EDT   E=JAN  F=
PS          MO=FEB E=FEB
PS          MO=MAR E=MAR
PS          MO=APR E=APR
PS          MO=MAY E=MAY
PS          MO=JUN E=JUN
PS          MO=JUL E=JUL
PS          MO=AUG E=AUG
PS          MO=SEP E=SEP
PS          MO=OCT E=OCT
PS          MO=NOV E=NOV
PS          MO=DEC E=DEC


LINK        HREL      GRANITE_P GRANITE
LD          Power Release from Granite Reservoir
PQ          MO=JAN-FEB B=GRANITE_P           C=FLOW-PNLTY_HPE E=DEC-FEB
PQ          MO=MAR     B=GRANITE_P           C=FLOW-PNLTY_HPE E=MAR_NOV
PQ          MO=APR-MAY B=GRANITE_P           C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ          MO=JUN-SEP B=GRANITE_P           C=FLOW-PNLTY_HPE E=JUN-SEP
PQ          MO=OCT     B=GRANITE_P           C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ          MO=NOV     B=GRANITE_P           C=FLOW-PNLTY_HPE E=MAR_NOV
PQ          MO=DEC     B=GRANITE_P           C=FLOW-PNLTY_HPE E=DEC-FEB
```

```
LINK        RRELEASE  GRANITE    MCNARY_P
LD          Release from Granite/Goose/Monumental/Ice Harbor to McNary Reservoir
PQ          MO=JAN        B=GRANITE_P        C=FLOW-PNLTY_EDT E=JAN F=
PQ          MO=FEB E=FEB
PQ          MO=MAR E=MAR
PQ          MO=APR E=APR
PQ          MO=MAY E=MAY
PQ          MO=JUN E=JUN
PQ          MO=JUL E=JUL
PQ          MO=AUG E=AUG
PQ          MO=SEP E=SEP
PQ          MO=OCT E=OCT
PQ          MO=NOV E=NOV
PQ          MO=DEC E=DEC


LINK        INFLOW    S_SOURCE  MCNARY_P  1.0        0.0
LD          Inflow to Mc Nary Reservoir
IN          B=MCNARY_P C=FLOW_LOC E=1MON F=INC-NAT80


LINK        RSTORAGE  MCNARY_P  MCNARY_P  1.0                    1170.0    1350.0
LD          Storage in Mc Nary Reservoir
PS          MO=JAN        B=MCNARY_P C=STOR-PNLTY_EDT  E=JAN F=
PS          MO=FEB E=FEB
PS          MO=MAR E=MAR
PS          MO=APR E=APR
PS          MO=MAY E=MAY
PS          MO=JUN E=JUN
PS          MO=JUL E=JUL
PS          MO=AUG E=AUG
PS          MO=SEP E=SEP
PS          MO=OCT E=OCT
PS          MO=NOV E=NOV
PS          MO=DEC E=DEC


LINK        HREL        MCNARY_P  MCNARY
LD          Power Release from McNary Reservoir
PQ          MO=JAN-FEB B=MCNARY_P        C=FLOW-PNLTY_HPE E=DEC-FEB
PQ          MO=MAR      B=MCNARY_P        C=FLOW-PNLTY_HPE E=MAR_NOV
PQ          MO=APR-MAY B=MCNARY_P        C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ          MO=JUN-SEP B=MCNARY_P        C=FLOW-PNLTY_HPE E=JUN-SEP
PQ          MO=OCT      B=MCNARY_P        C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ          MO=NOV      B=MCNARY_P        C=FLOW-PNLTY_HPE E=MAR_NOV
PQ          MO=DEC      B=MCNARY_P        C=FLOW-PNLTY_HPE E=DEC-FEB


LINK        RRELEASE  MCNARY    J.DAY_P
LD          Channel from Mc Nary to John Day
PQ          MO=JAN-DEC    B=MCNARY_P        C=FLOW-PNLTY_EDT E=JAN F=ZERO


LINK        INFLOW    S_SOURCE  J.DAY_P  1.0        0.0
LD          Inflow to John Day
IN          B=J.DAY_P C=FLOW_LOC E=1MON F=INC-NAT80


LINK        RSTORAGE  J.DAY_P   J.DAY_P   1.0                    1989.0    2523.0
LD          Storage in John Day Reservoir
PS          MO=JAN        B=J.DAY_P  C=STOR-PNLTY_EDT  E=JAN  F=
PS          MO=FEB E=FEB
PS          MO=MAR E=MAR
PS          MO=APR E=APR
PS          MO=MAY E=MAY
PS          MO=JUN E=JUN
PS          MO=JUL E=JUL
PS          MO=AUG E=AUG
PS          MO=SEP E=SEP
PS          MO=OCT E=OCT
PS          MO=NOV E=NOV
PS          MO=DEC E=DEC
```

```
LINK       HREL       J.DAY_P    J.DAY
LD         Power Release from John Day Reservoir
PQ         MO=JAN-FEB B=J.DAY_P        C=FLOW-PNLTY_HPE E=DEC-FEB
PQ         MO=MAR     B=J.DAY_P        C=FLOW-PNLTY_HPE E=MAR_NOV
PQ         MO=APR-MAY B=J.DAY_P        C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ         MO=JUN-SEP B=J.DAY_P        C=FLOW-PNLTY_HPE E=JUN-SEP
PQ         MO=OCT     B=J.DAY_P        C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ         MO=NOV     B=J.DAY_P        C=FLOW-PNLTY_HPE E=MAR_NOV
PQ         MO=DEC     B=J.DAY_P        C=FLOW-PNLTY_HPE E=DEC-FEB

LINK       RRELEASE   J.DAY      DALLES_P
LD         Release from John Day to the Dalles & Bonneville Reservoirs
PQ         MO=JAN-DEC    B=J.DAY_P        C=FLOW-PNLTY_EDT E=JAN F=ZERO

LINK       INFLOW     S_SOURCE DALLES_P    1.0        0.0
LD         Inflow to The Dalles & Bonneville Reservoirs
IN         B=DALLES_P   C=FLOW_LOC E=1MON F=INC-NAT80

LINK       RSTORAGE   DALLES_P  DALLES_P 1.0         0.0         999.0       999.0
LD         Storage in The Dalles and Bonneville Reservoirs
PS         MO=JAN-DEC    B=DALLES_P C=STOR-PNLTY_EDT   E=JAN F=ZERO

LINK       HREL       DALLES_P  DALLES
LD         Power Release from The Dalles
PQ         MO=JAN-FEB B=DALLES_P        C=FLOW-PNLTY_HPE E=DEC-FEB F=
PQ         MO=MAR     B=DALLES_P        C=FLOW-PNLTY_HPE E=MAR_NOV
PQ         MO=APR-MAY B=DALLES_P        C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ         MO=JUN-SEP B=DALLES_P        C=FLOW-PNLTY_HPE E=JUN-SEP
PQ         MO=OCT     B=DALLES_P        C=FLOW-PNLTY_HPE E=APR-MAY_OCT
PQ         MO=NOV     B=DALLES_P        C=FLOW-PNLTY_HPE E=MAR_NOV
PQ         MO=DEC     B=DALLES_P        C=FLOW-PNLTY_HPE E=DEC-FEB

LINK       RREL       DALLES     SINK
LD         Release from The Dalles & Bonneville to the Sink
PQ         MO=JAN        B=DALLES_P     C=FLOW-PNLTY_EDT E=JAN F=
PQ         MO=FEB E=FEB
PQ         MO=MAR E=MAR
PQ         MO=APR E=APR
PQ         MO=MAY E=MAY
PQ         MO=JUN E=JUN
PQ         MO=JUL E=JUL
PQ         MO=AUG E=AUG
PQ         MO=SEP E=SEP
PQ         MO=OCT E=OCT
PQ         MO=NOV E=NOV
PQ         MO=DEC E=DEC

STOP
```

Appendix E

HEC-PRM Penalty Functions for Selected Locations

Appendix E

HEC-PRM Penalty Functions for Selected Locations

Figures

Appendix E

HEC-PRM Penalty Functions for Selected Locations

INTRODUCTION

This appendix includes the edited penalty functions developed for the HEC-PRM models (alternatives 1, 2, and 3). The basic data for the penalty functions were developed by NPD district and division staff jointly with IWR. Penalty function development is documented in a separate report to be published by IWR.

Penalty data for the individual operation purposes are combined to yield composite functions for model locations. These composite functions are edited with computer program PENF to develop the convex, piecewise-linear approximation required.

Example plots of each of the three types of economic penalty functions (storage, flow and energy) are included. To facilitate comparison of penalties between locations, consistent scales have been selected. The following graphs show monthly functions plotted with the following scales: (1) reservoir storage penalty from 0 to $14 million, storage from 0 to 10 million acre-feet per month; (2) flow penalty from 0 to $60 million, flow from 0 to 600,000 cfs; (3) energy flow penalty from 0 to $250 million, flow from 0 to 600,000 cfs.

Storage penalties for Grand Coulee and Dworshak are shown in Figures E.1 through E.3. Flow penalties for Granite and The Dalles are shown in Figures E.4 through E.6. Energy penalties for Grand Coulee, Dworshak, Granite and The Dalles are shown in Figures E.7 through E.10.
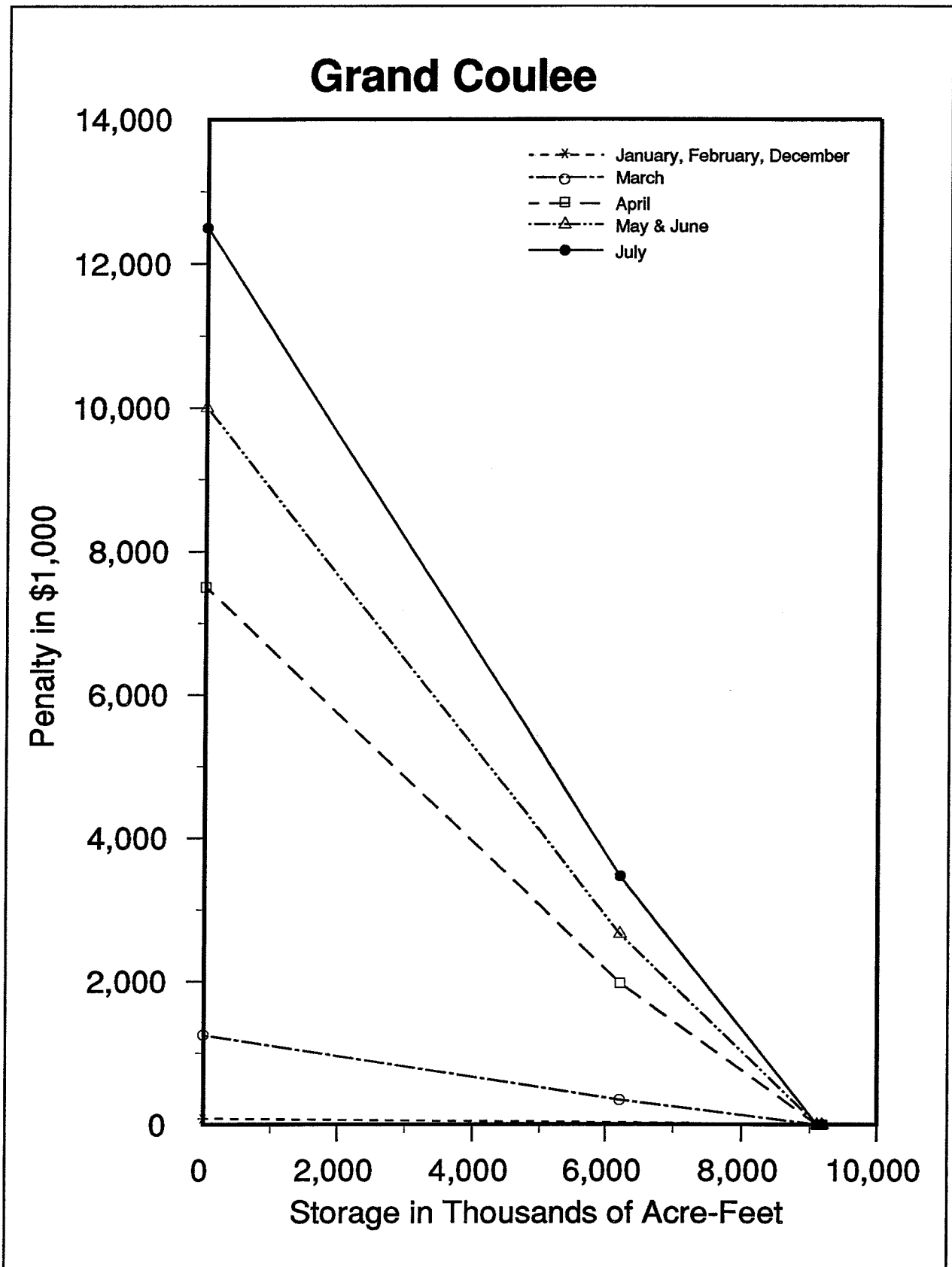
FIGURE E.1 Grand Coulee Storage Penalty Functions (January - July, December)
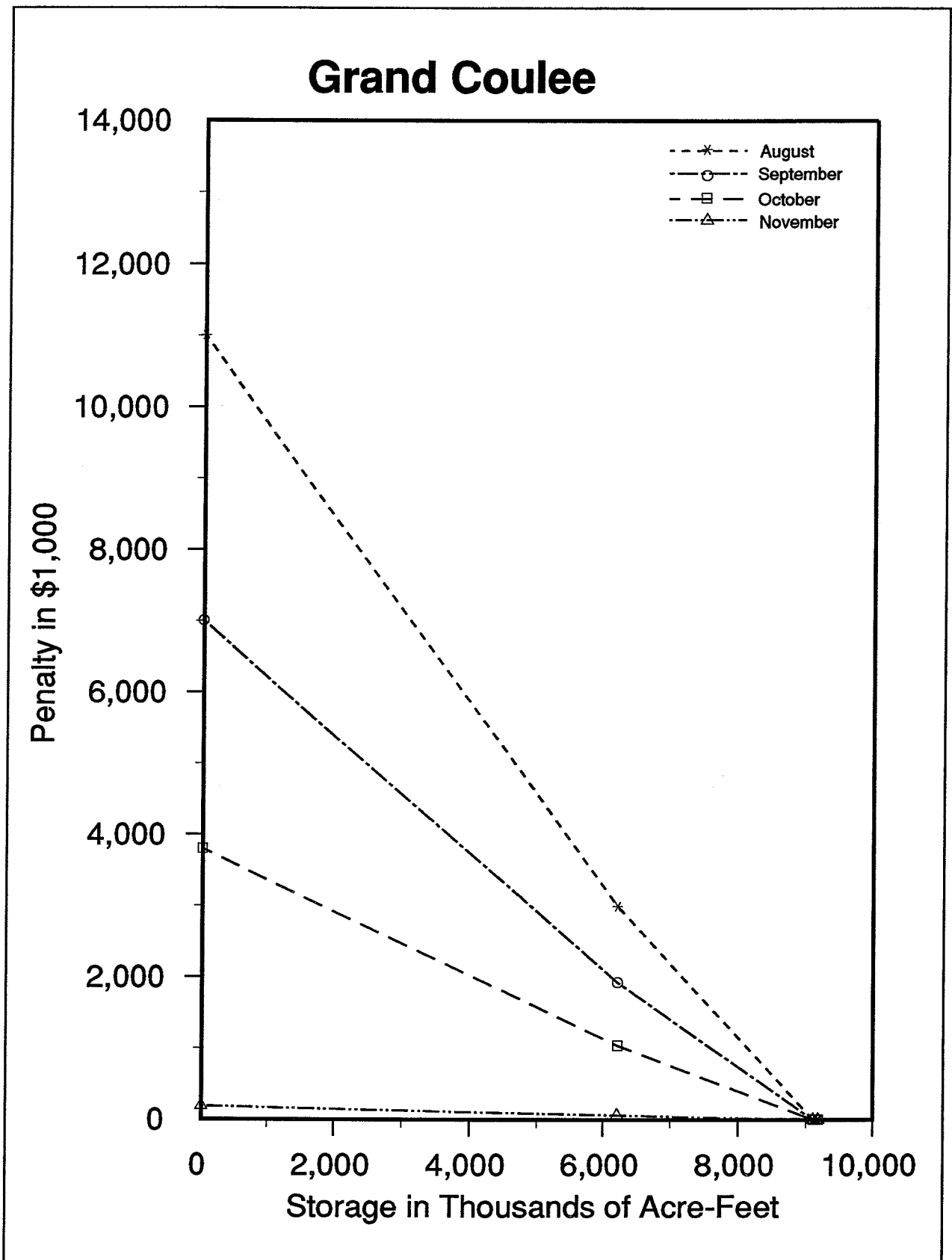
FIGURE E.2 Grand Coulee Storage Penalty Functions (August - November)
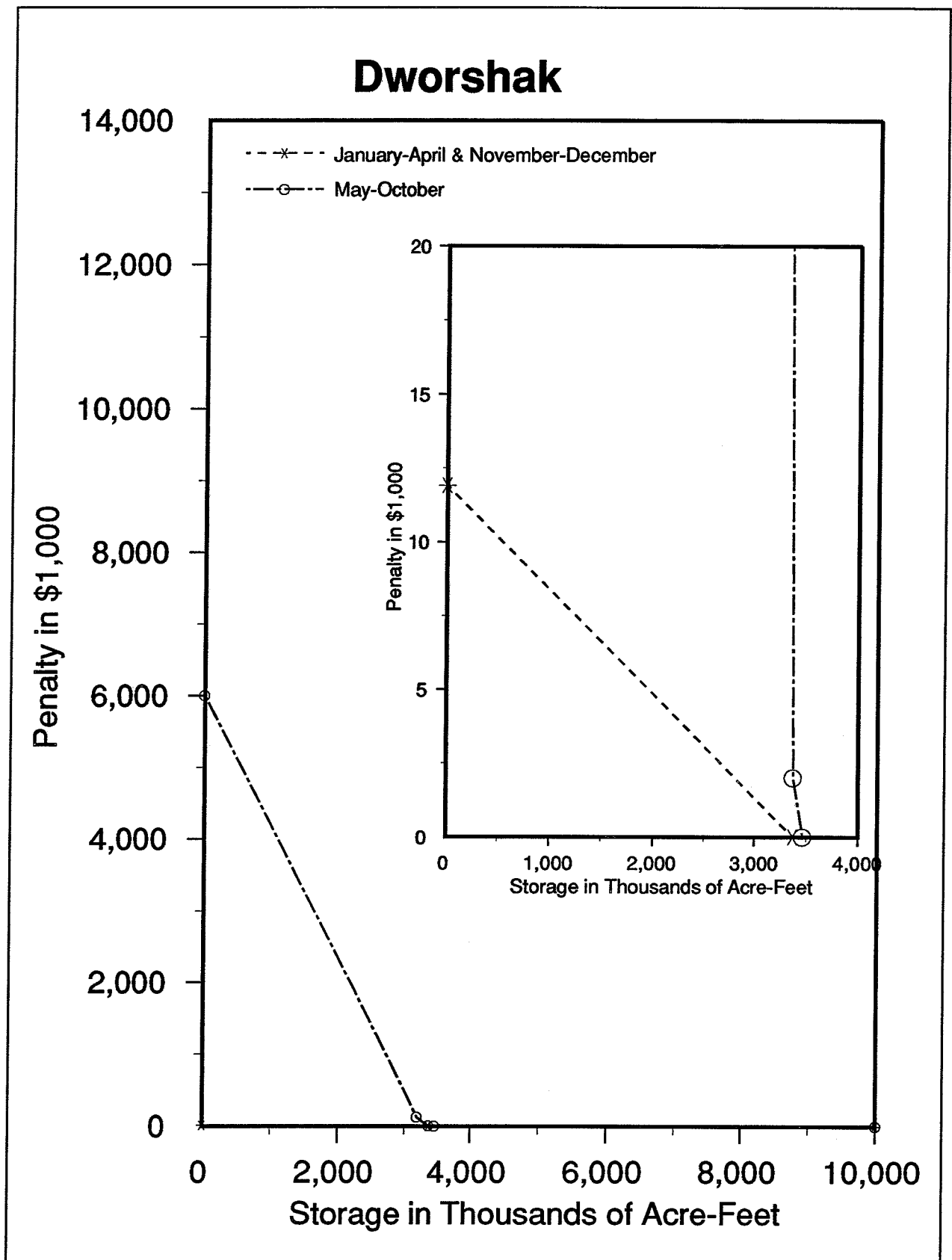
FIGURE E.3 Dworshak Storage Penalty Functions

FIGURE E.4 Lower Granite/L. Goose/L. Monumental/Ice Harbor Flow Penalty Functions
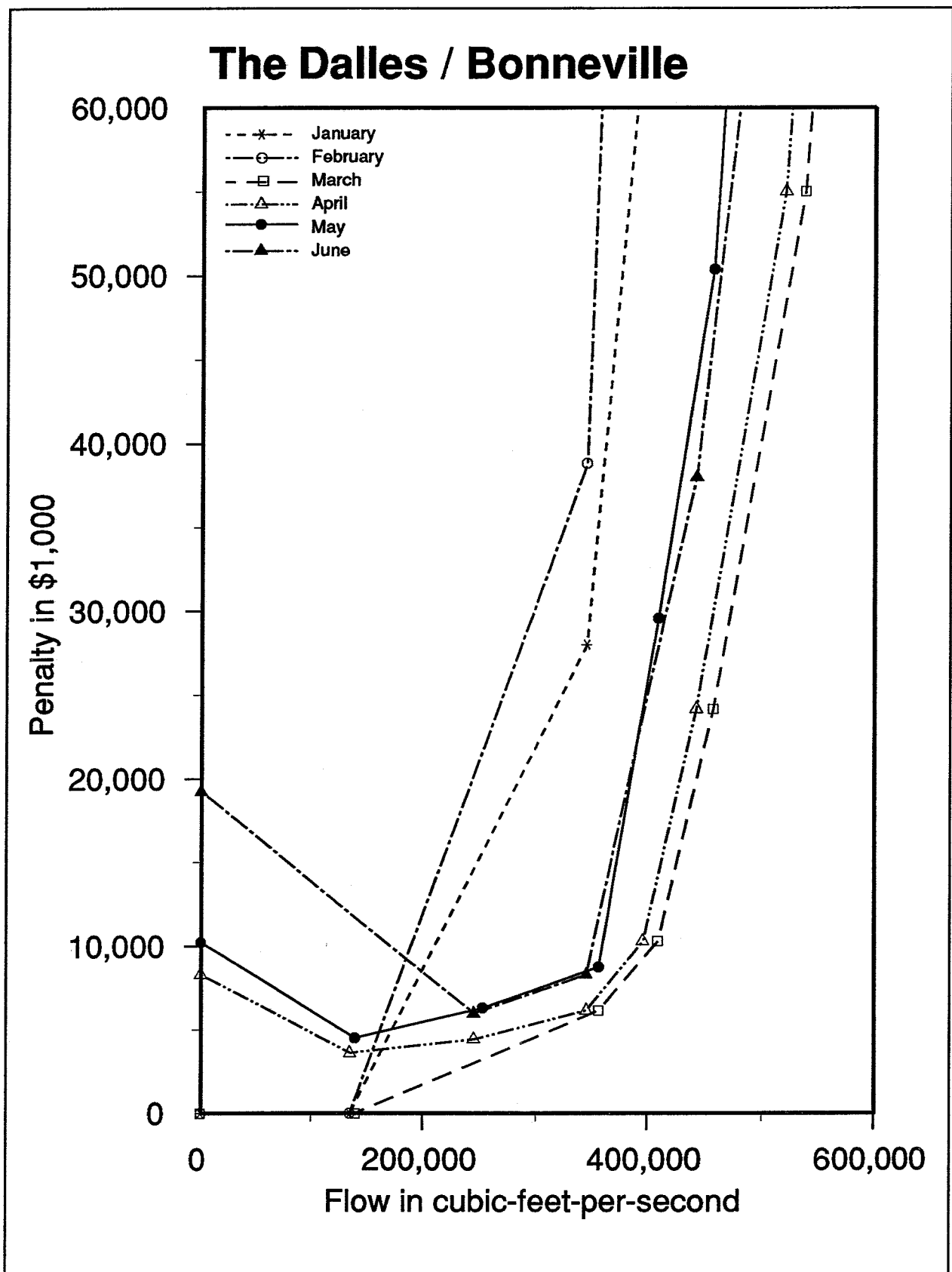
FIGURE E.5 The Dalles/Bonneville Flow Penalty Functions (January - June)
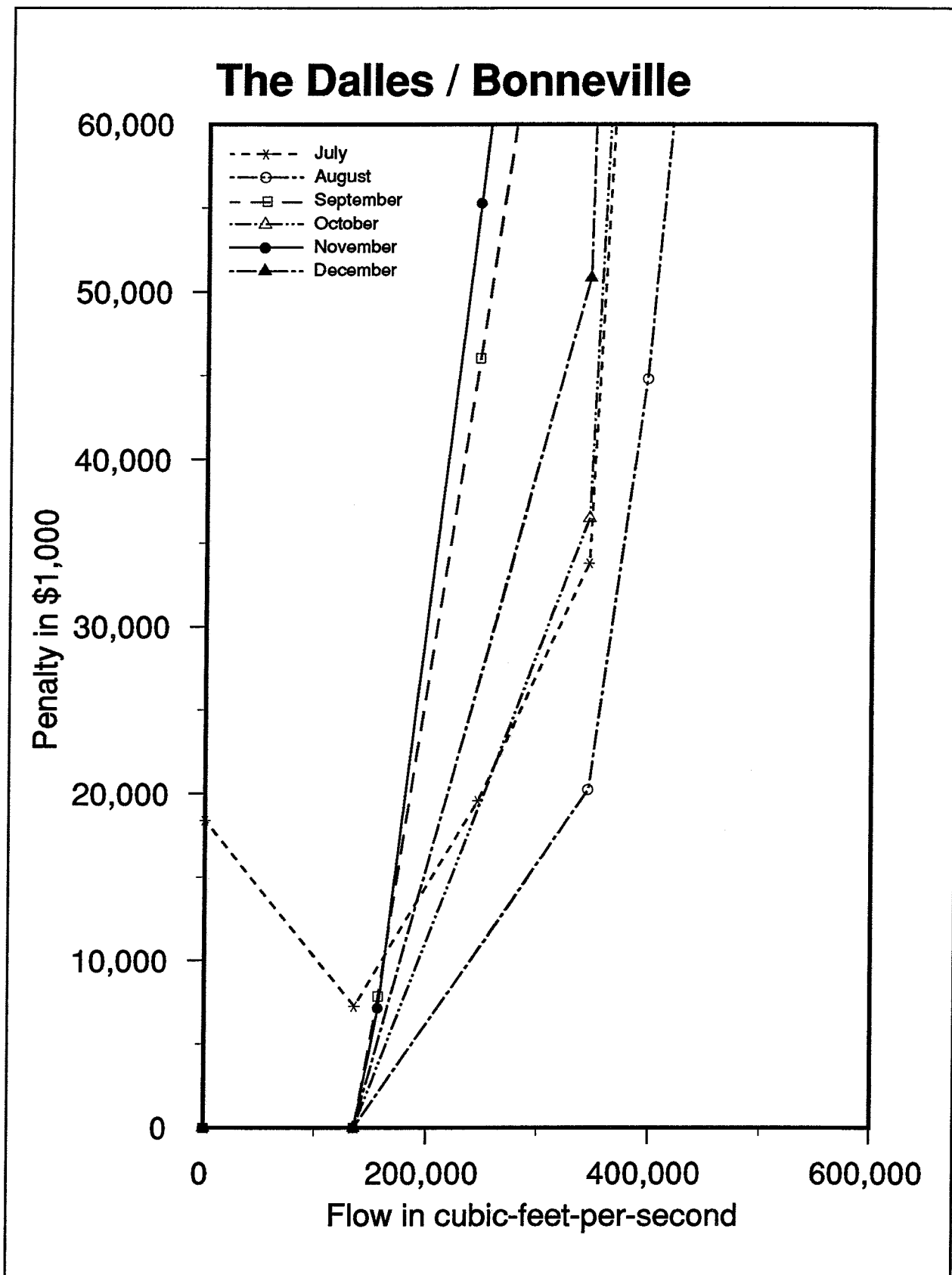
FIGURE E.6 The Dalles/Bonneville Flow Penalty Function (July - December)
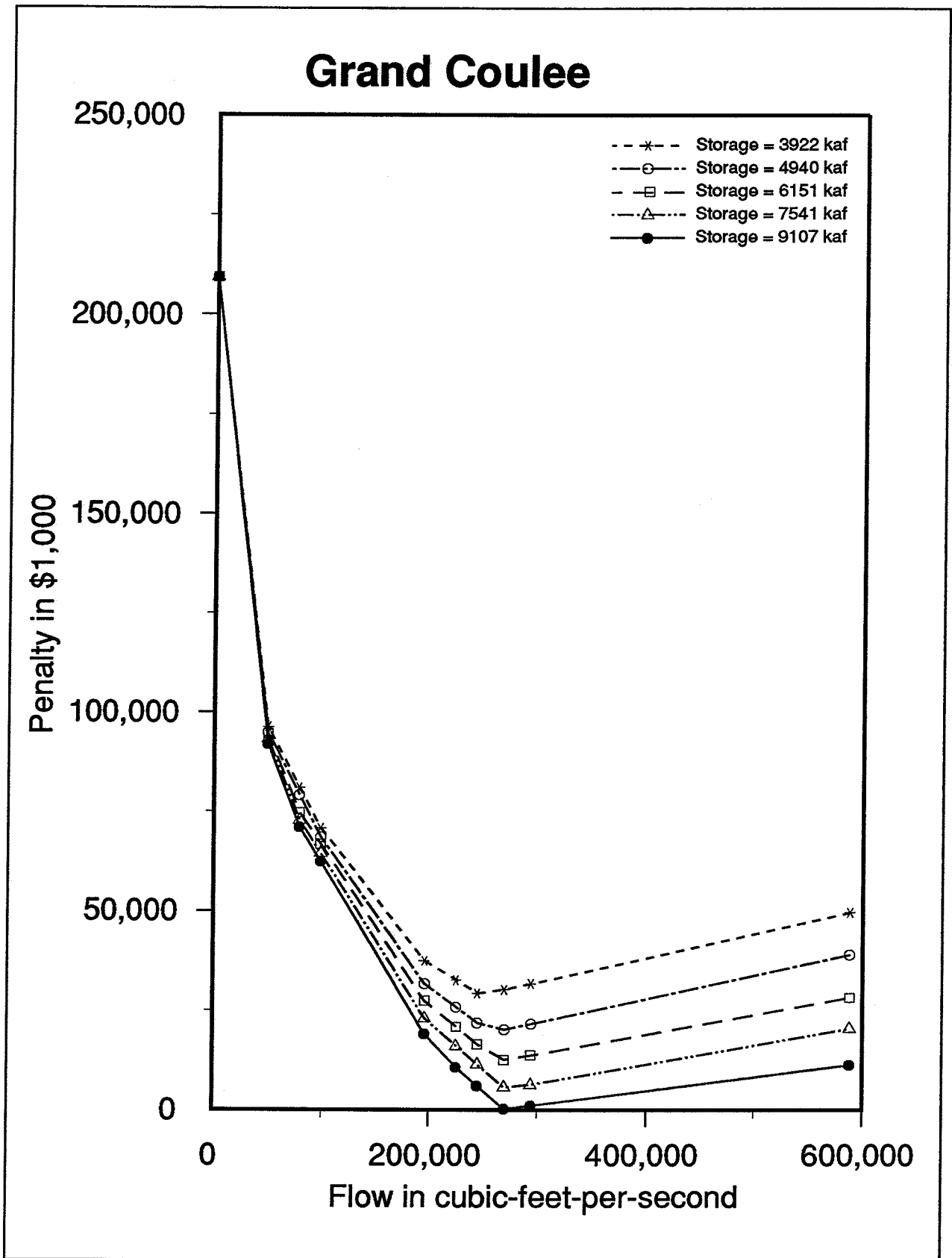
FIGURE E.7 Grand Coulee Hydropower Penalty Functions
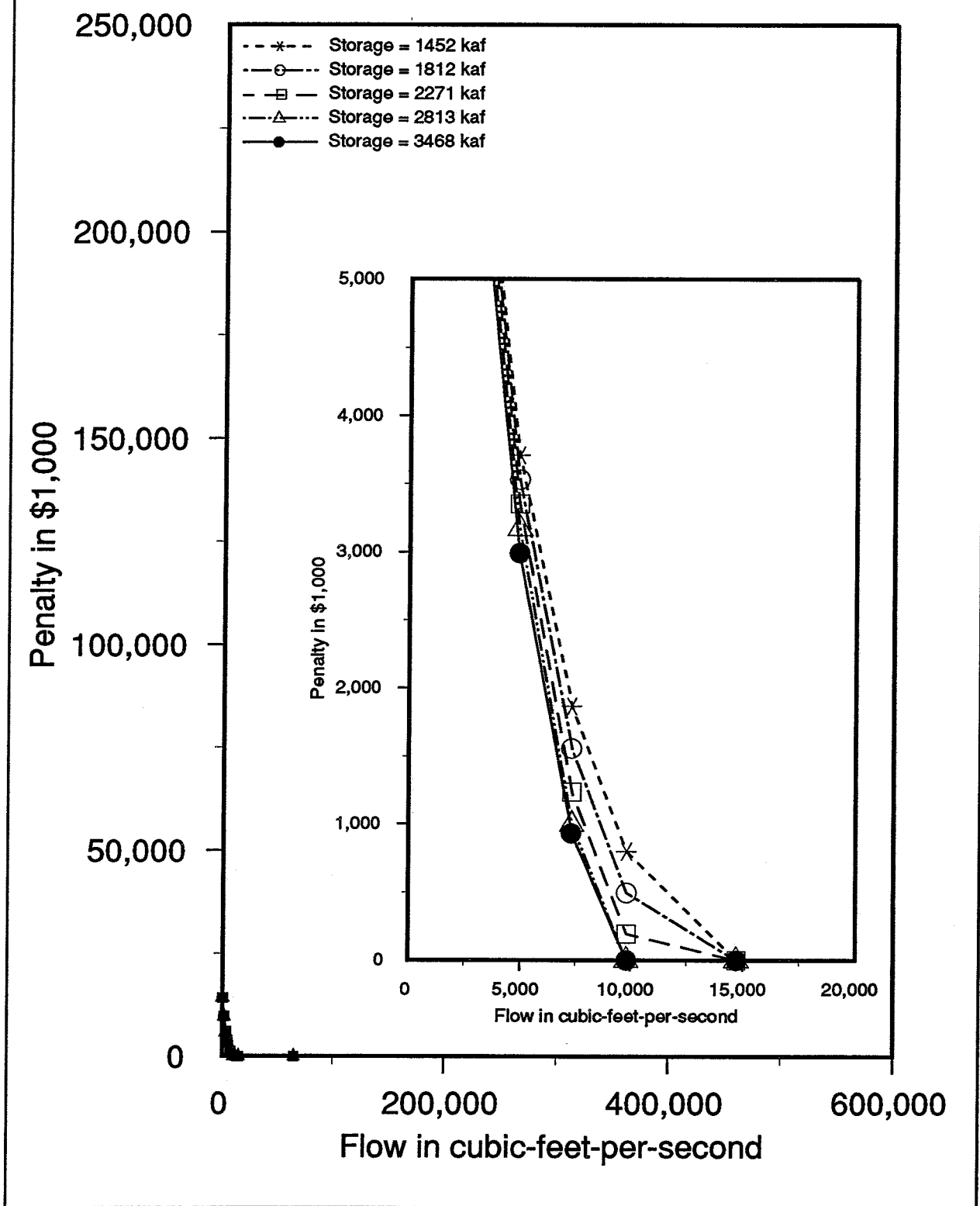
FIGURE E.8 Dworshak Hydropower Penalty Functions

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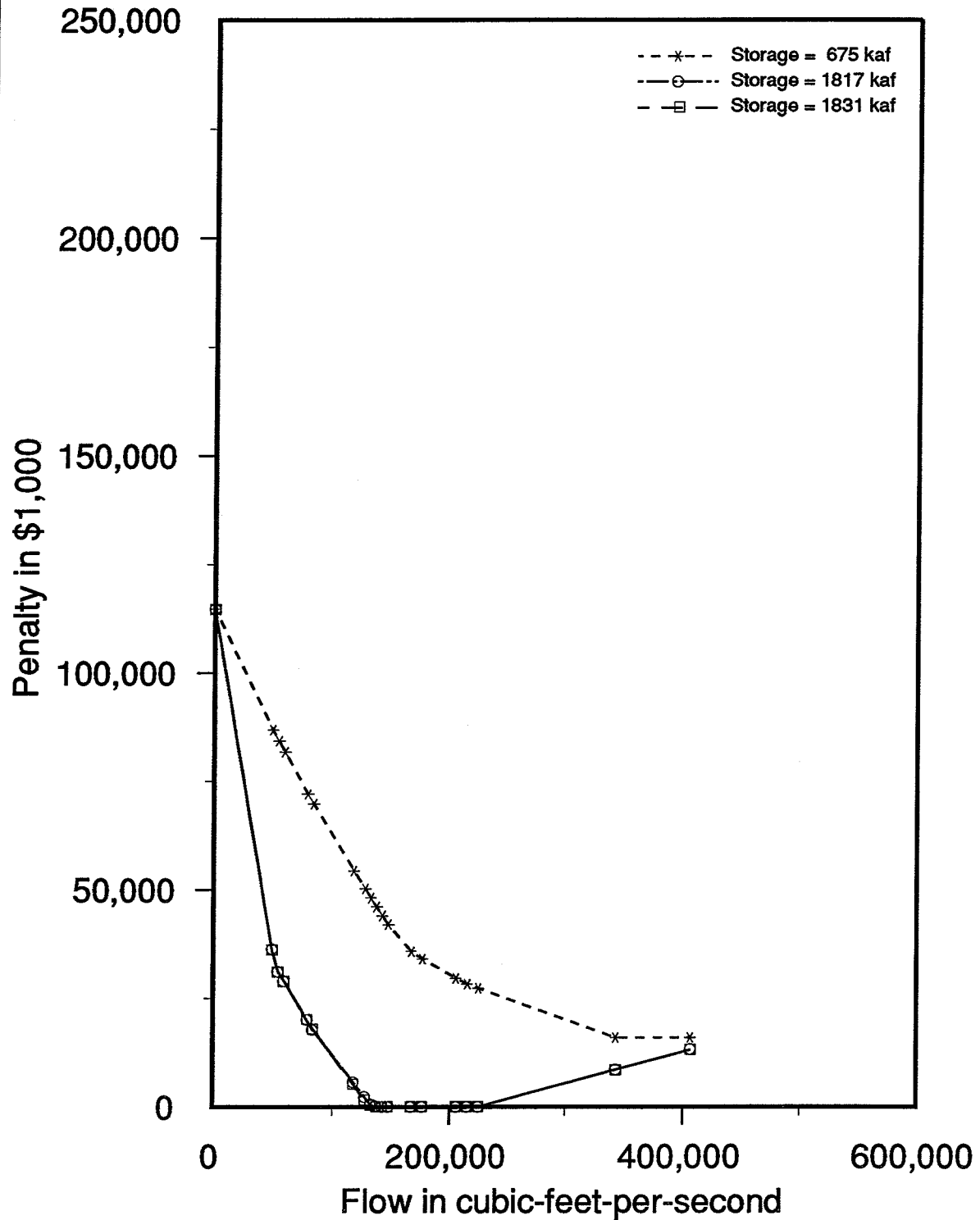
FIGURE E.9 **Lower Granite - Ice Harbor Hydropower Penalty Functions**
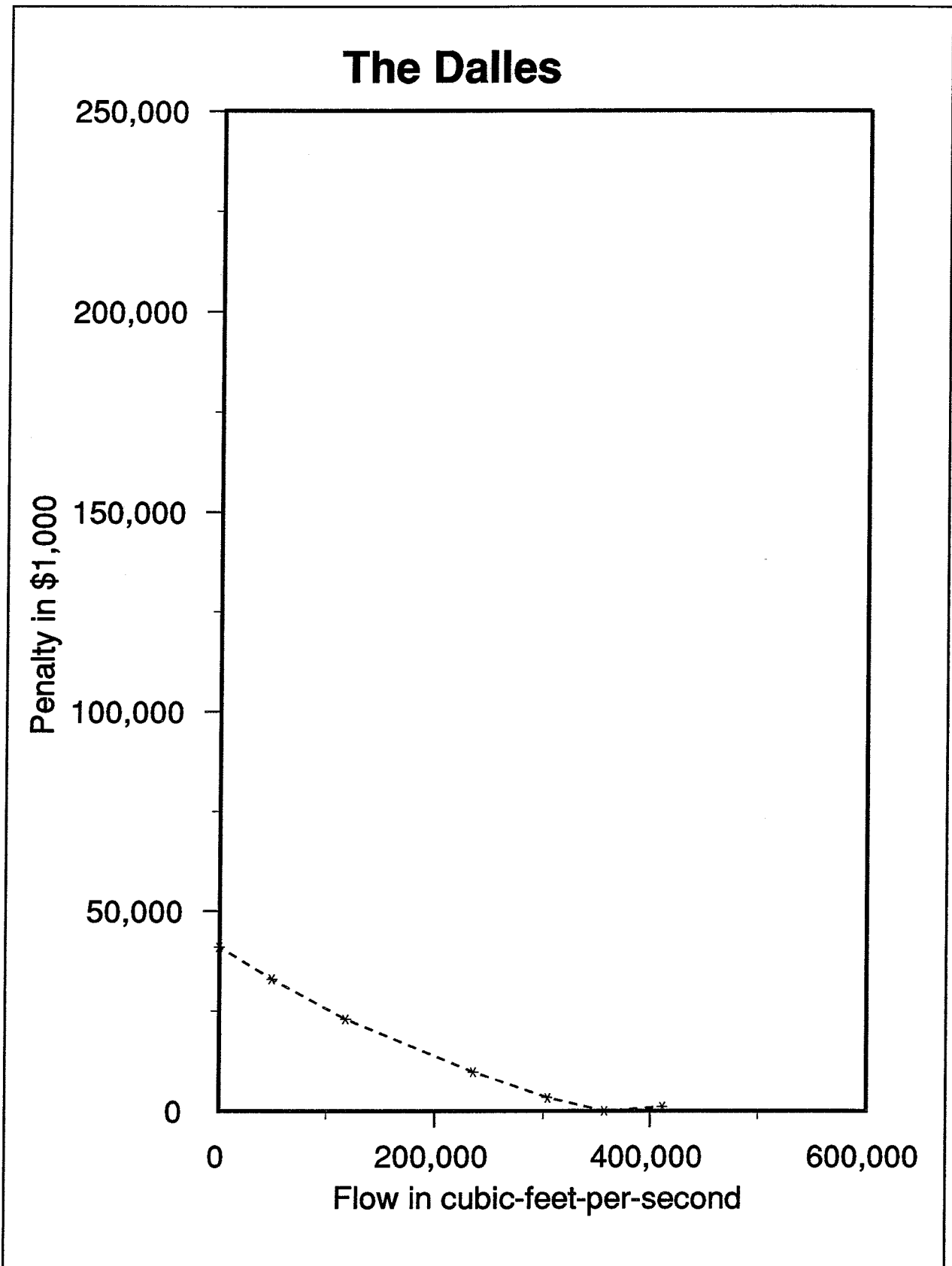
FIGURE E.10 The Dalles Hydropower Penalty Function

Appendix F

HEC-PRM Time-series Results for Selected Locations

Appendix F

HEC-PRM Time-series Results for Selected Locations

Figures

Appendix F

HEC-PRM Time-series Results for Selected Locations

INTRODUCTION

This appendix presents HEC-PRM model results for the three operation analysis alternatives compaired with NPD's HYSSR model simulation results.

Time-series results are shown in the figures that follow for the entire 50-year period of analysis (1928 - 1978) at four locations. These include storages from HYSSR and each of the three HEC-PRM alternatives at Grand Coulee, Mica and Dworshak reservoirs. In addition, flow at The Dalles for HYSSR and the HEC-PRM alternatives is shown. Storage limits specified in the HEC-PRM models are shown for reference on the storage plots.

Storage data for the period of 1928 through 1978 are shown as follows: Grand Coulee in Figures F.1 through F.5; Mica in Figures F.6 through F.10; and Dworshak in Figures F.11 through F.15. Flow data for The Dalles are shown in Figures F.16 through F.20.
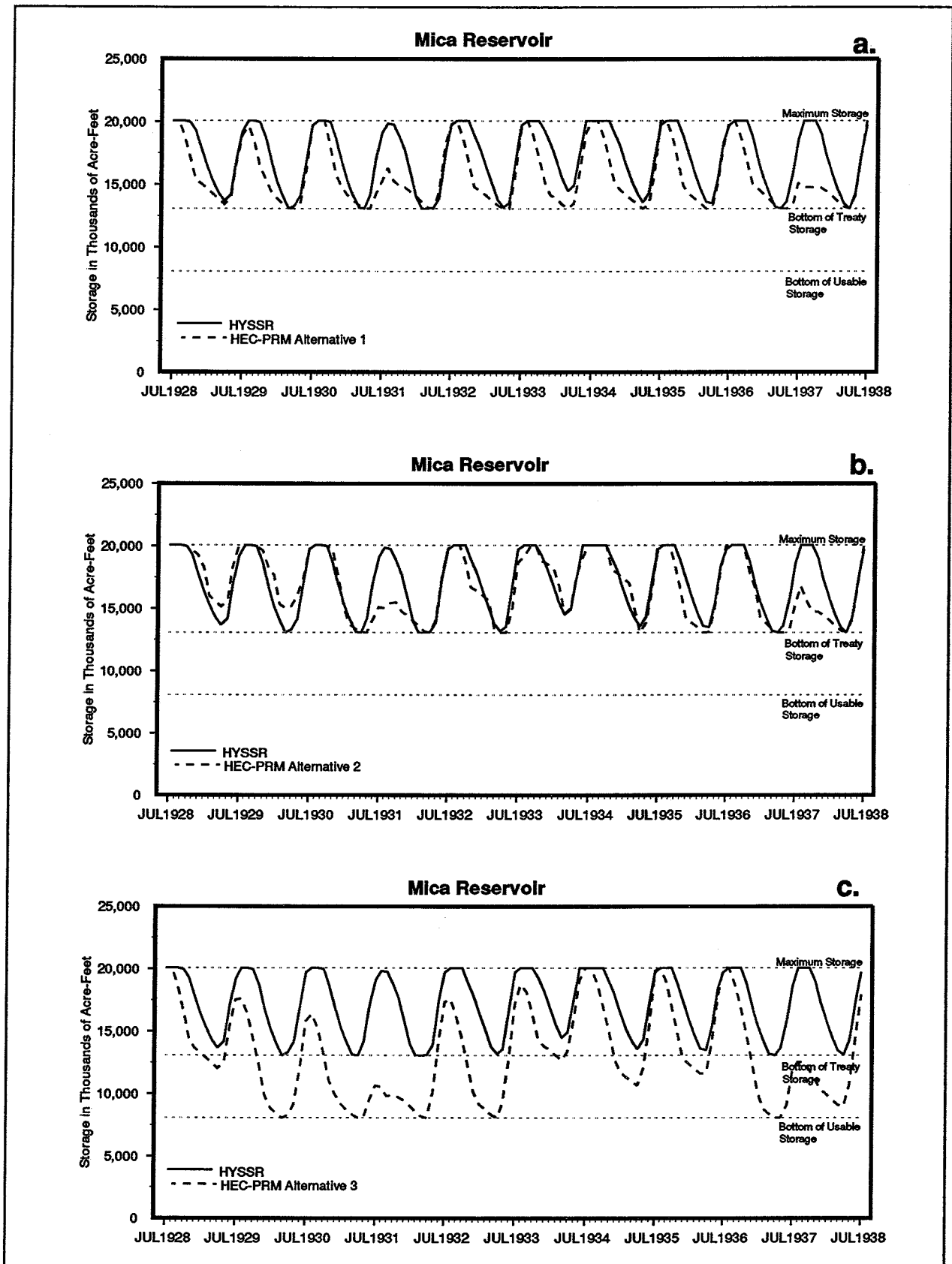
FIGURE F.1 1928 - 1938 Storage at Mica: HYSSR & Alternatives
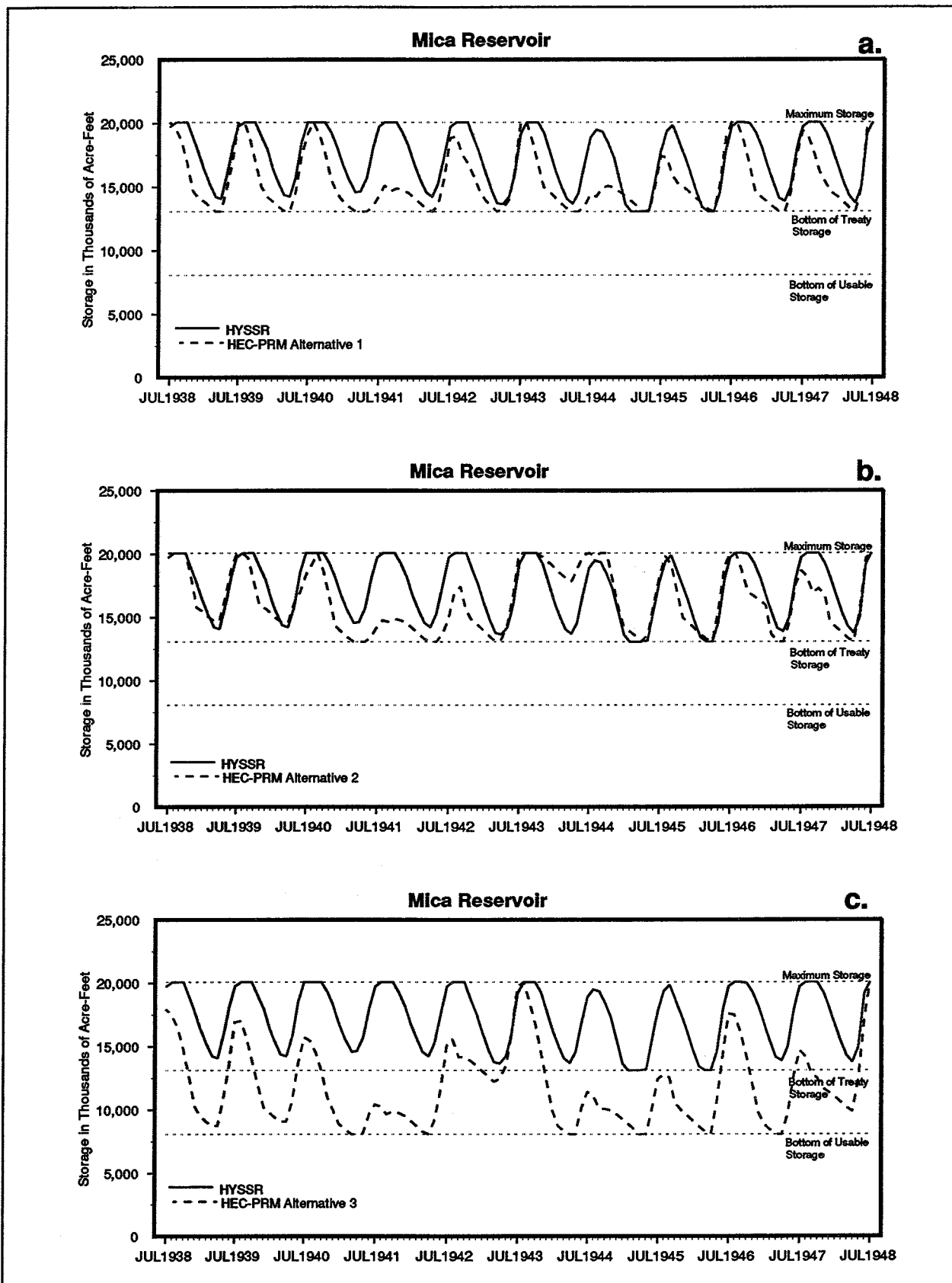
FIGURE F.2 1938 - 1948 Storage at Mica: HYSSR & Alternatives
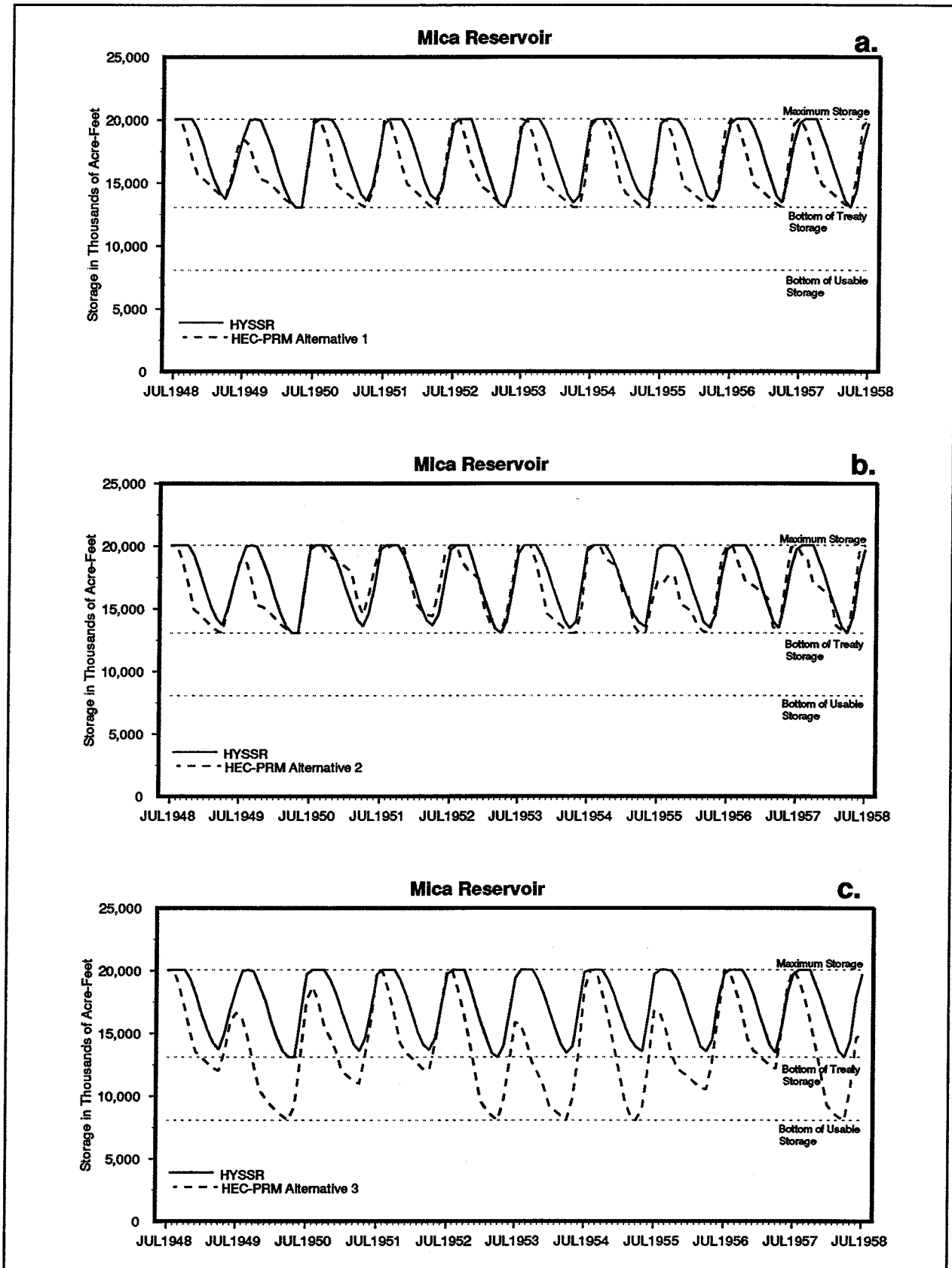
FIGURE F.3 1948 - 1958 Storage at Mica: HYSSR & Alternatives
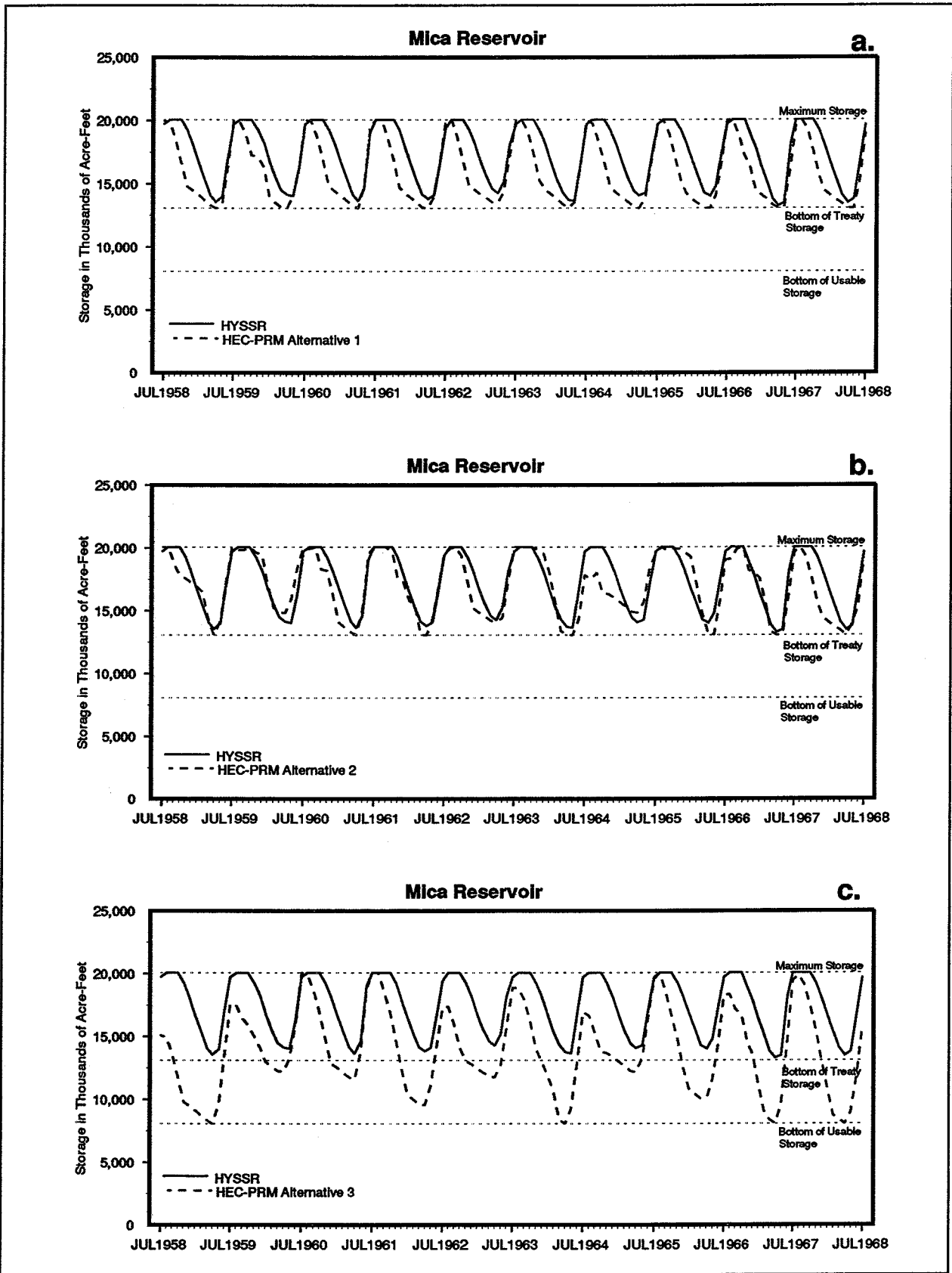
FIGURE F.4 1958 - 1968 Storage at Mica: HYSSR & Alternatives
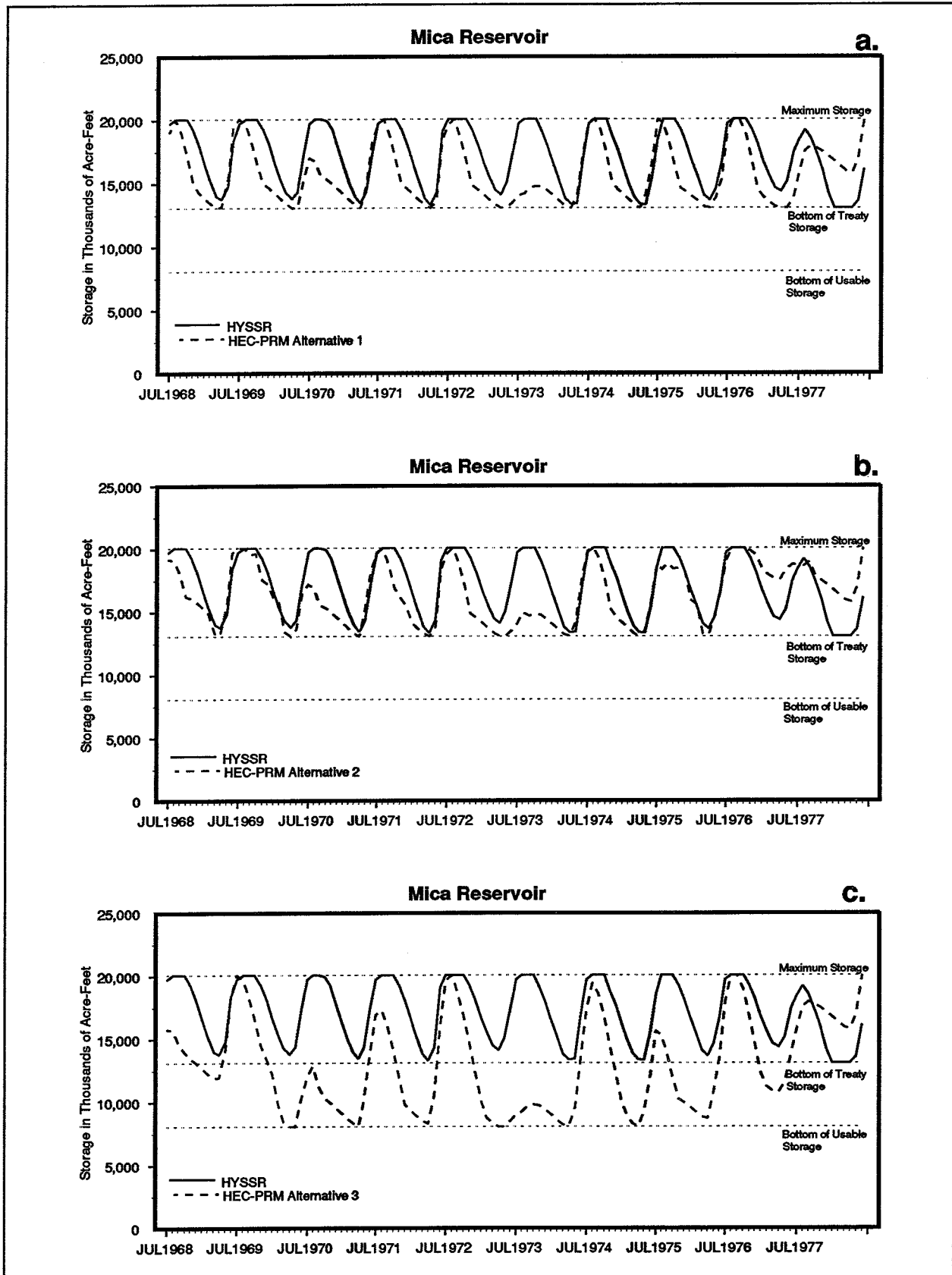
**FIGURE F.5 1968 - 1978 Storage at Mica: HYSSR & Alternatives**
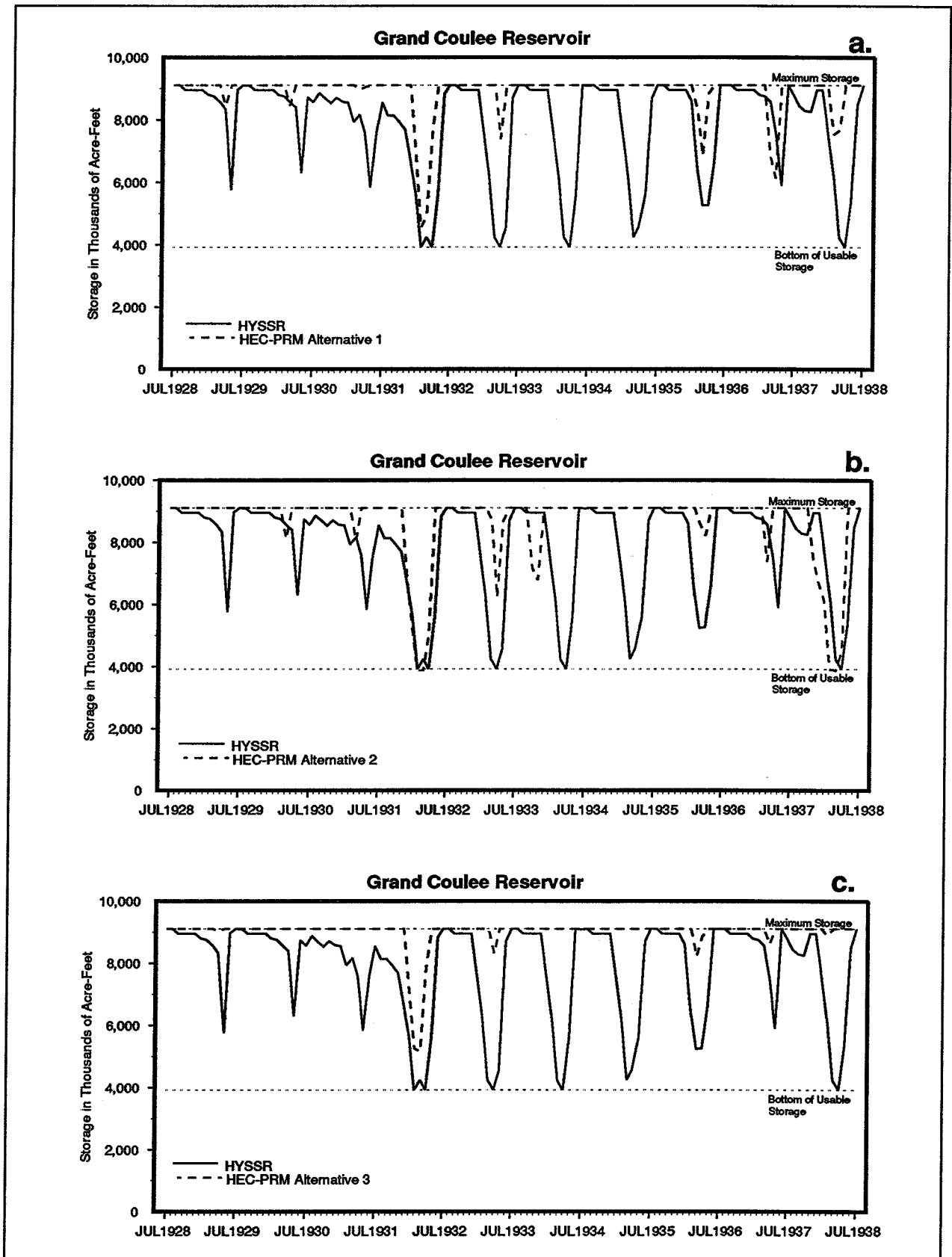
FIGURE F.6 1928 - 1938 Storage at Grand Coulee: HYSSR & Alternatives
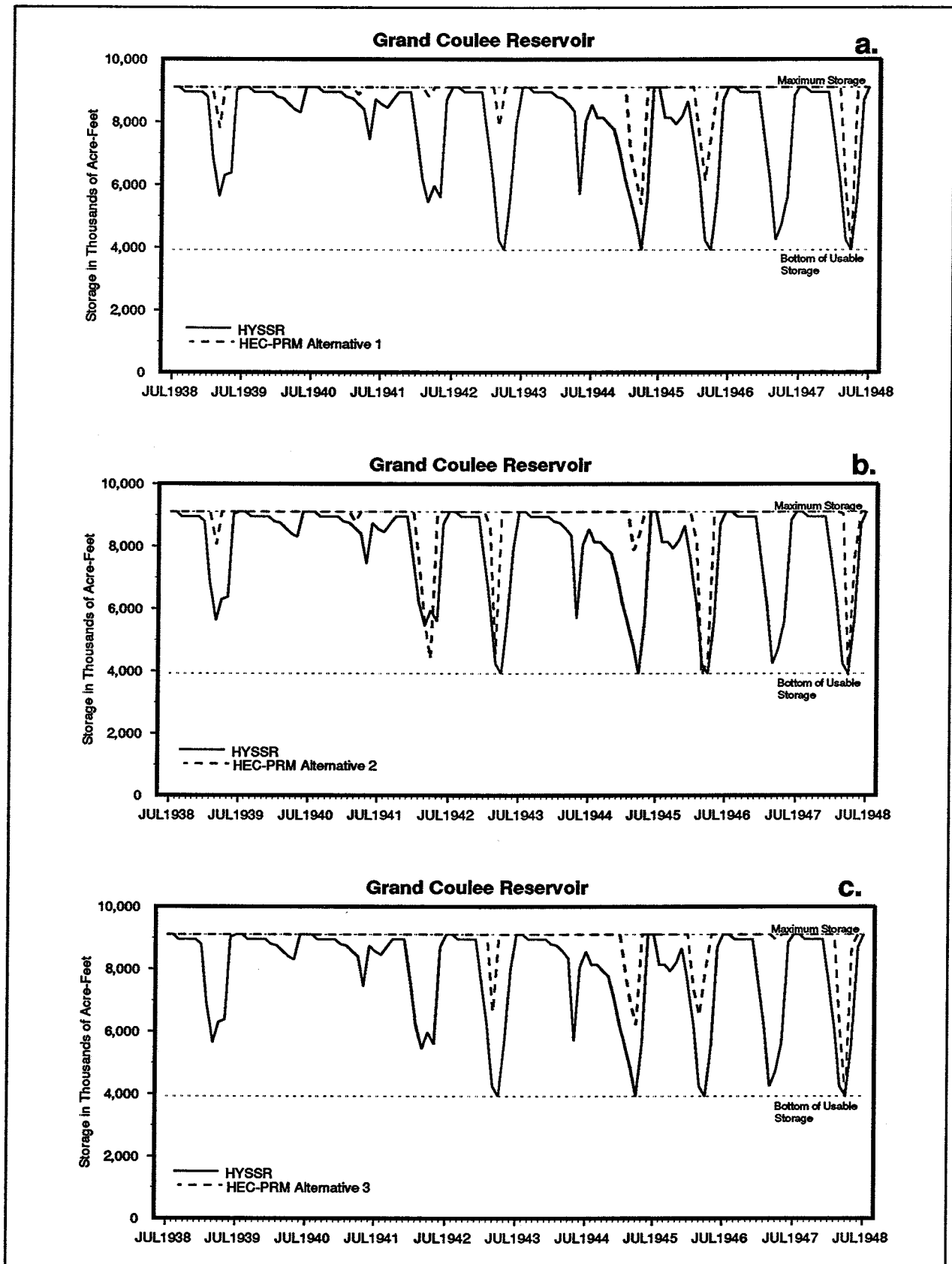
FIGURE F.7 1938 - 1948 Storage at Grand Coulee: HYSSR & Alternatives
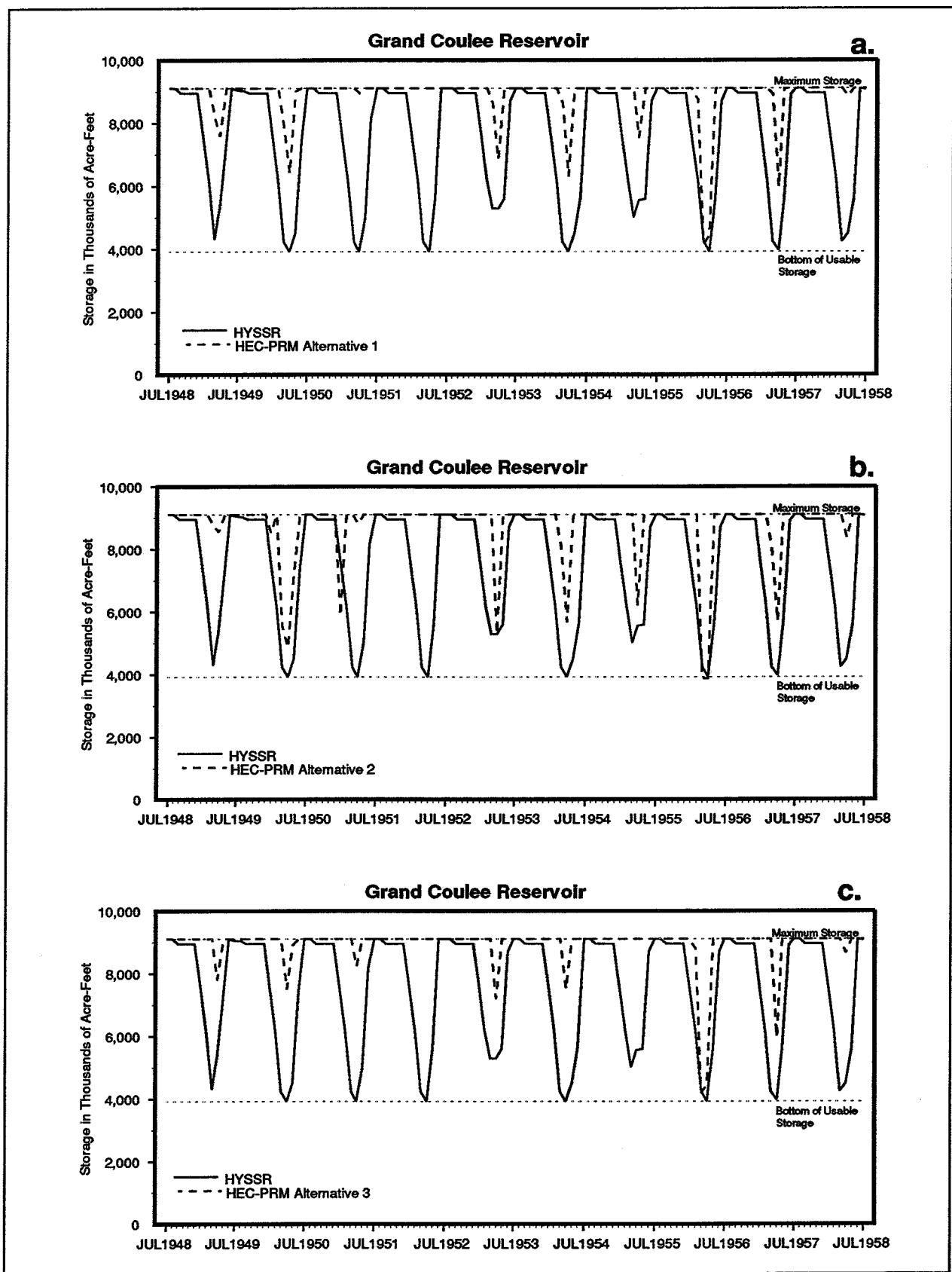
FIGURE F.8 1948 - 1958 Storage at Grand Coulee: HYSSR & Alternatives
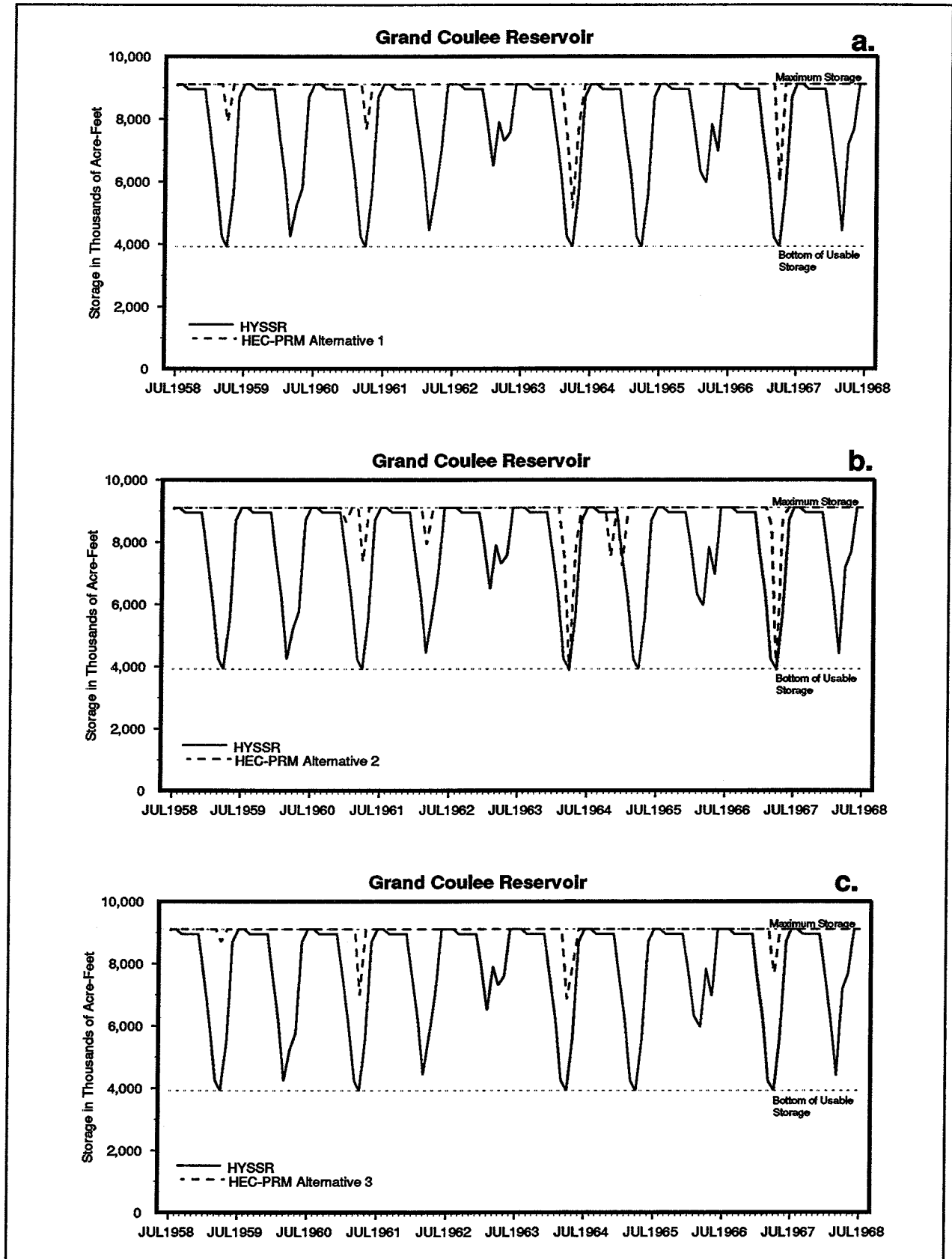
FIGURE F.9 1958 - 1968 Storage at Grand Coulee: HYSSR & Alternatives
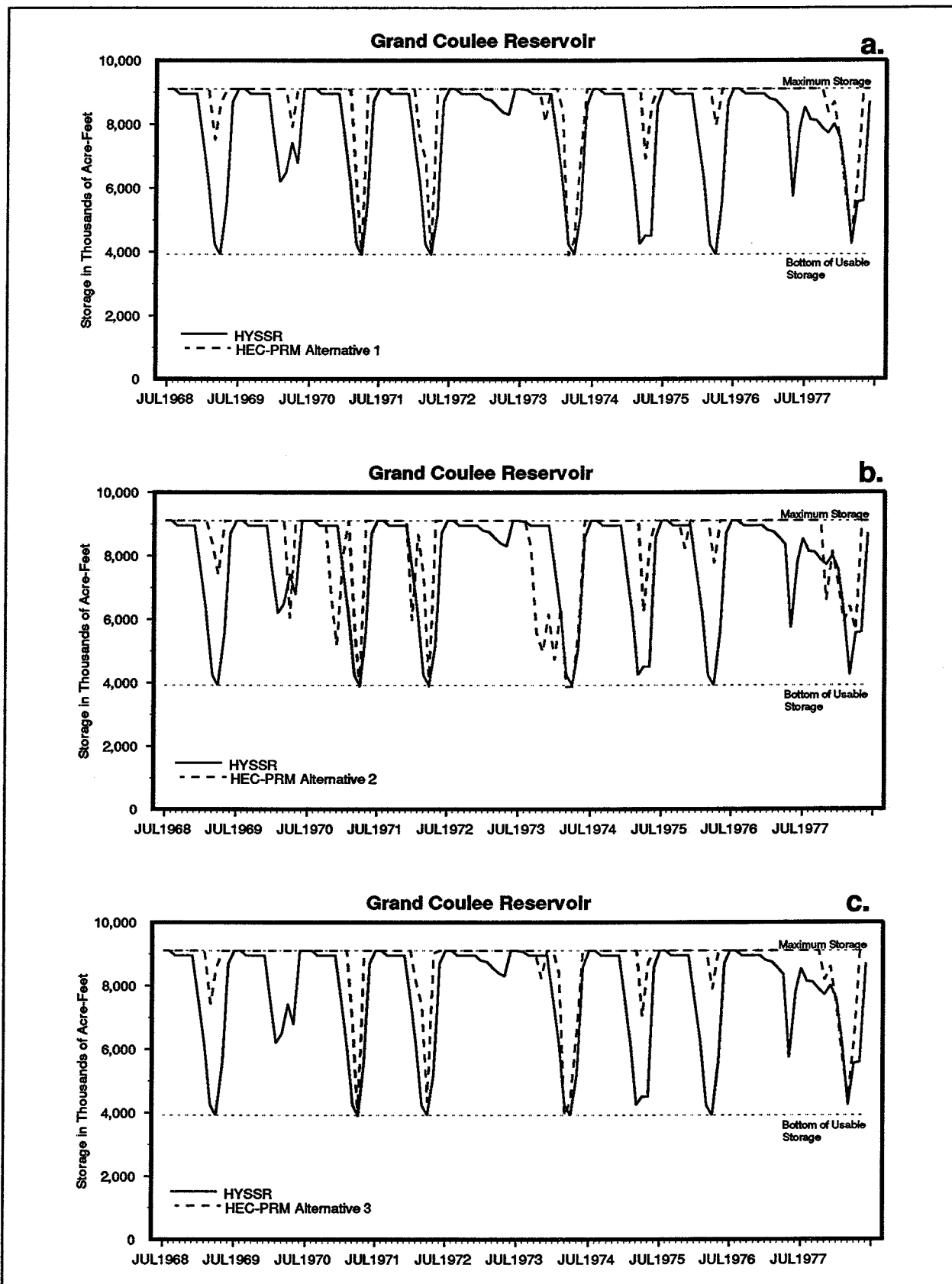
FIGURE F.10 1968 - 1978 Storage at Grand Coulee: HYSSR & Alternatives
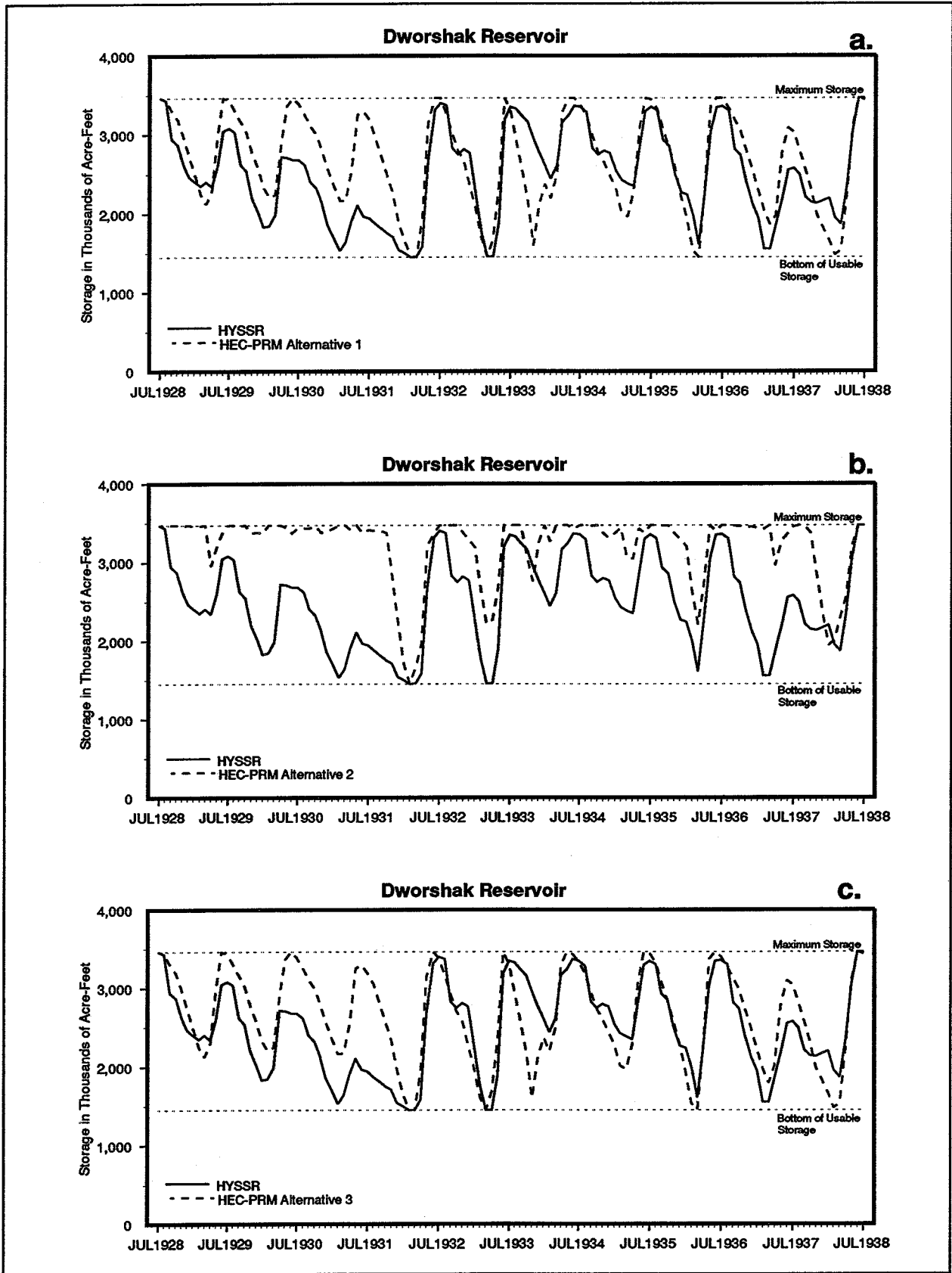
FIGURE F.11 1928 - 1938 Storage at Dworshak: HYSSR & Alternatives
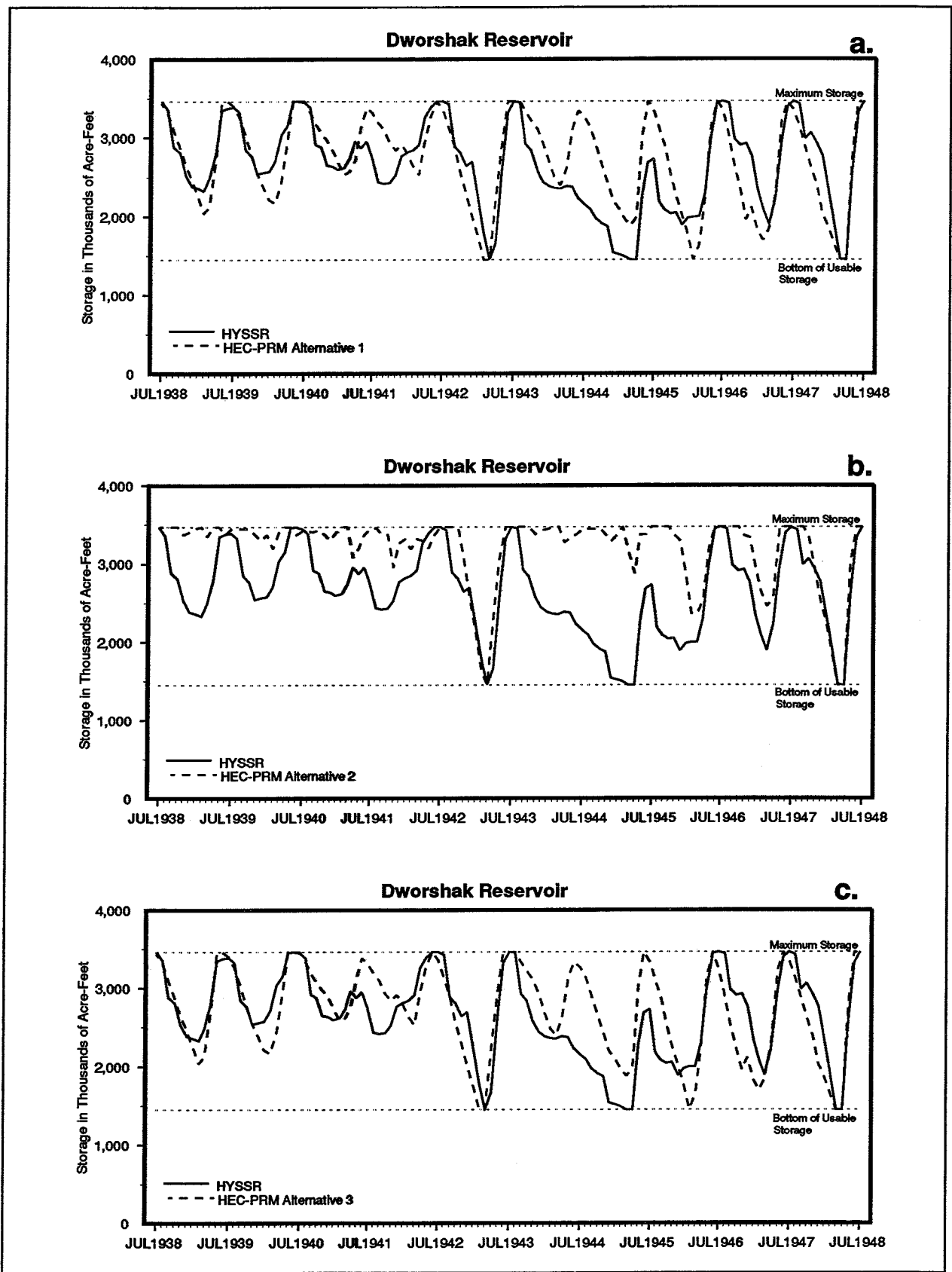
FIGURE F.12 1938 - 1948 Storage at Dworshak: HYSSR & Alternatives
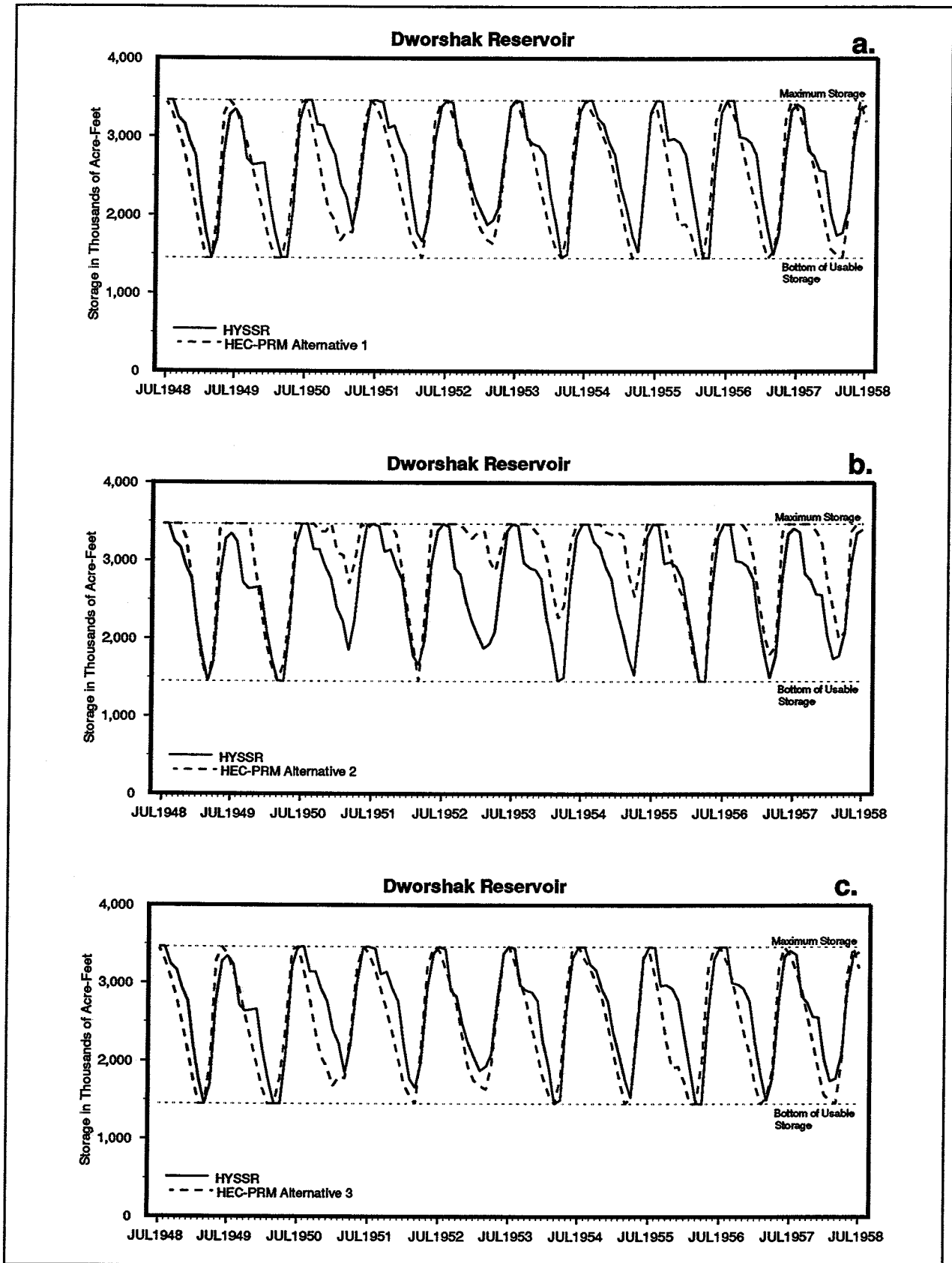
FIGURE F.13 1948 - 1958 Storage at Dworshak: HYSSR & Alternatives
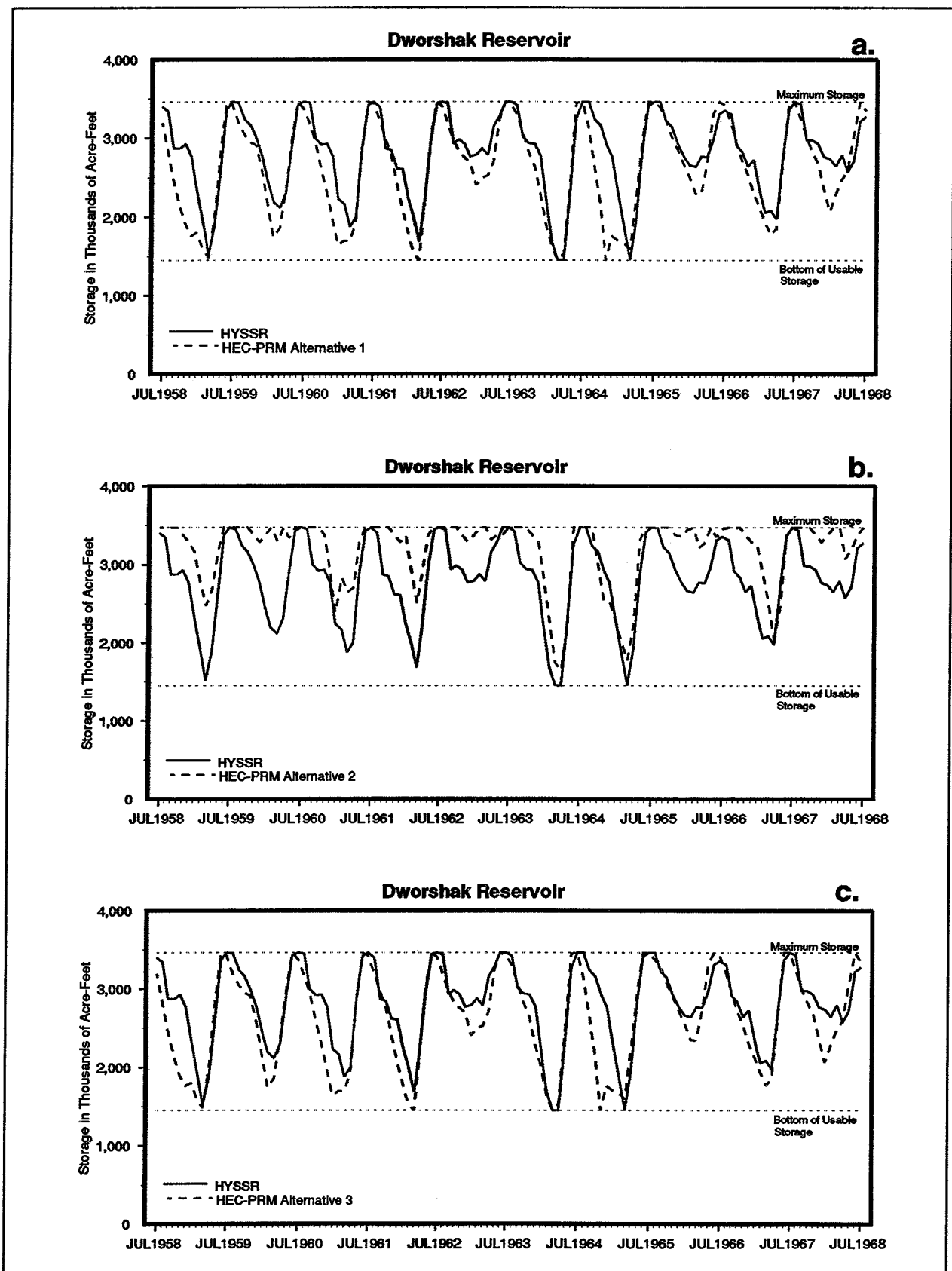
FIGURE F.14 1958 - 1968 Storage at Dworshak: HYSSR & Alternatives
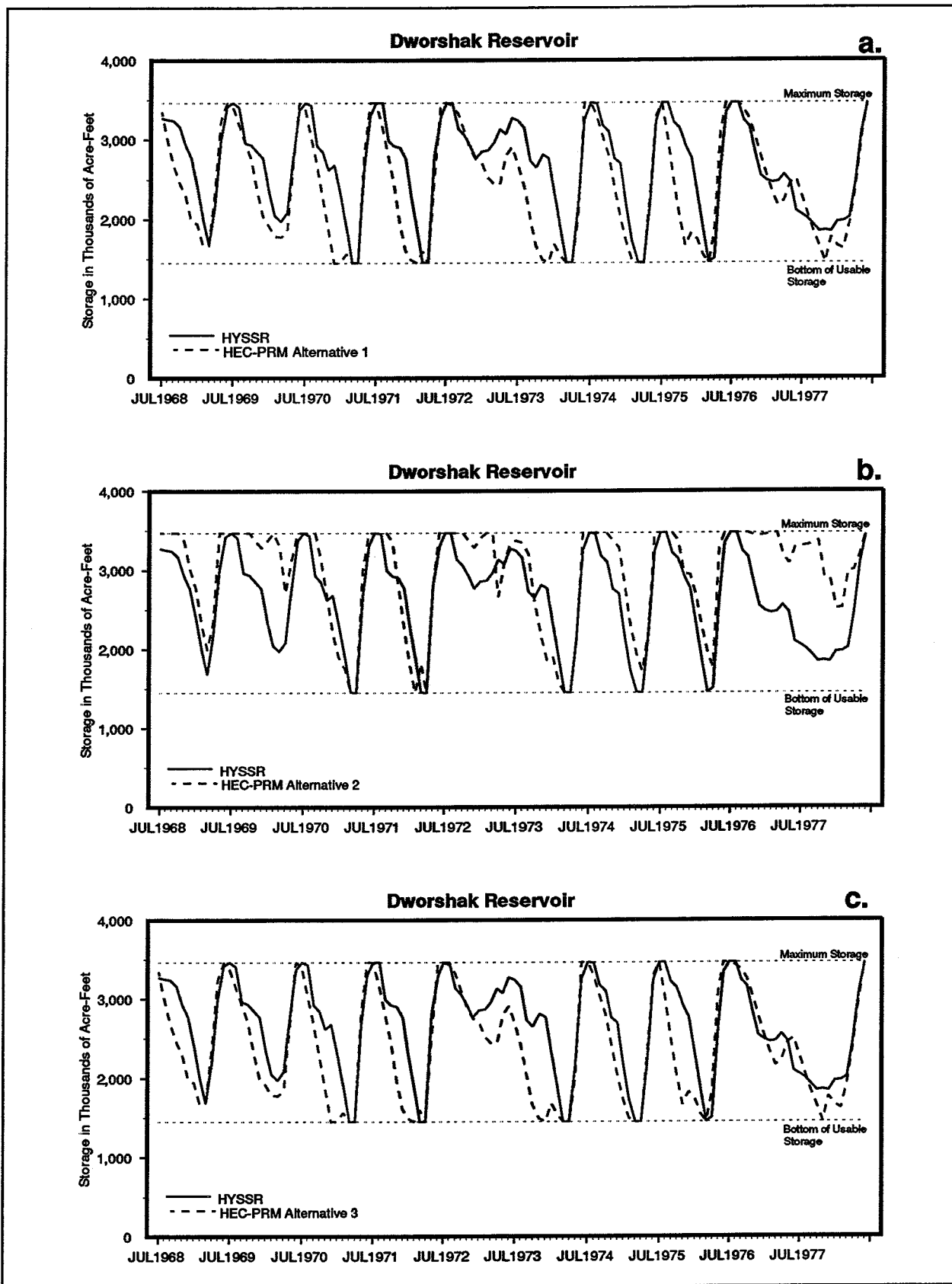
FIGURE F.15   1968 - 1978 Storage at Dworshak: HYSSR & Alternatives
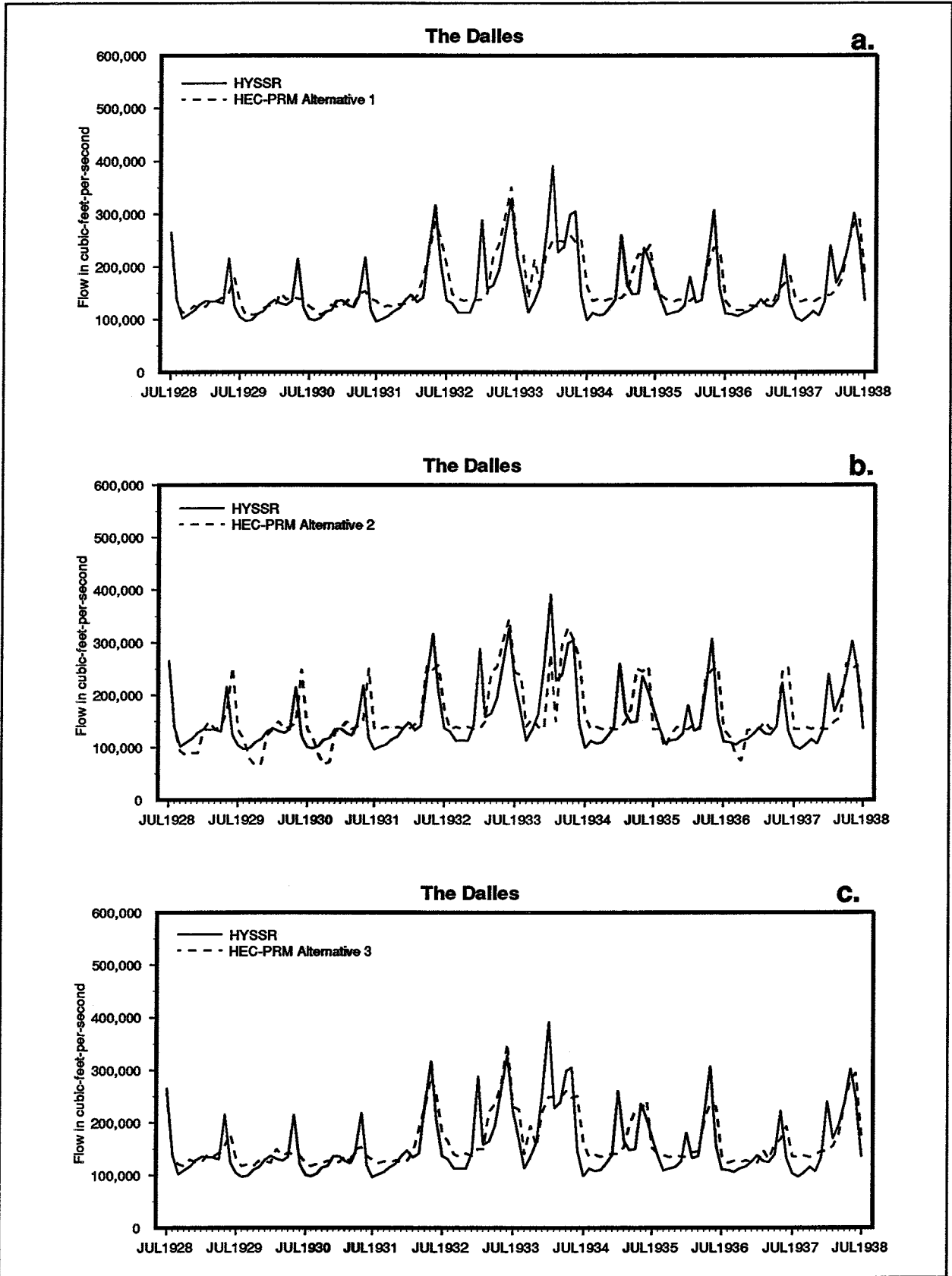
FIGURE F.16   1928 - 1938 Flow at The Dalles: HYSSR & Alternatives

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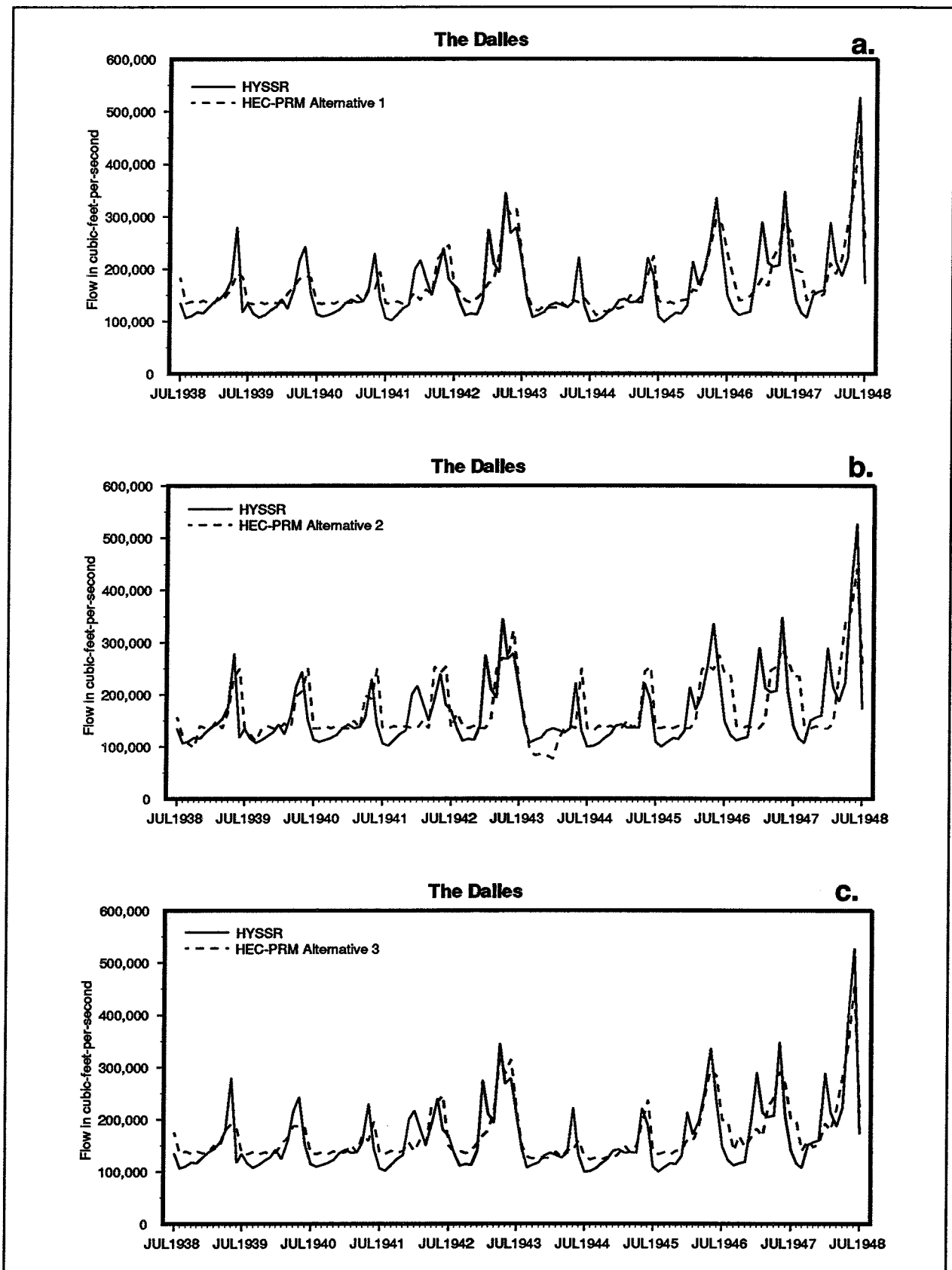
FIGURE F.17 1938 - 1948 Flow at The Dalles: HYSSR & Alternatives

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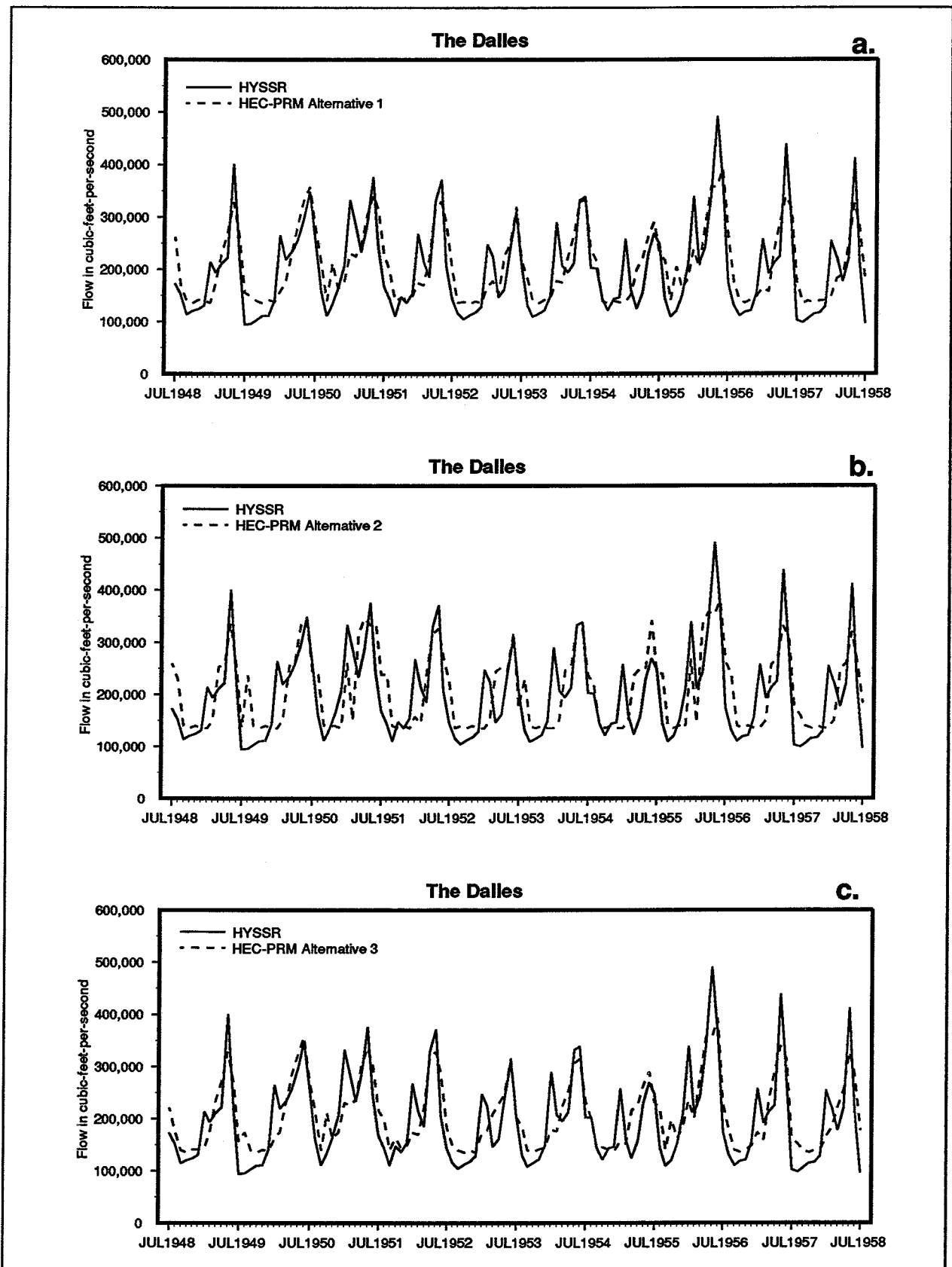
FIGURE F.18 1948 - 1958 Flow at The Dalles: HYSSR & Alternatives
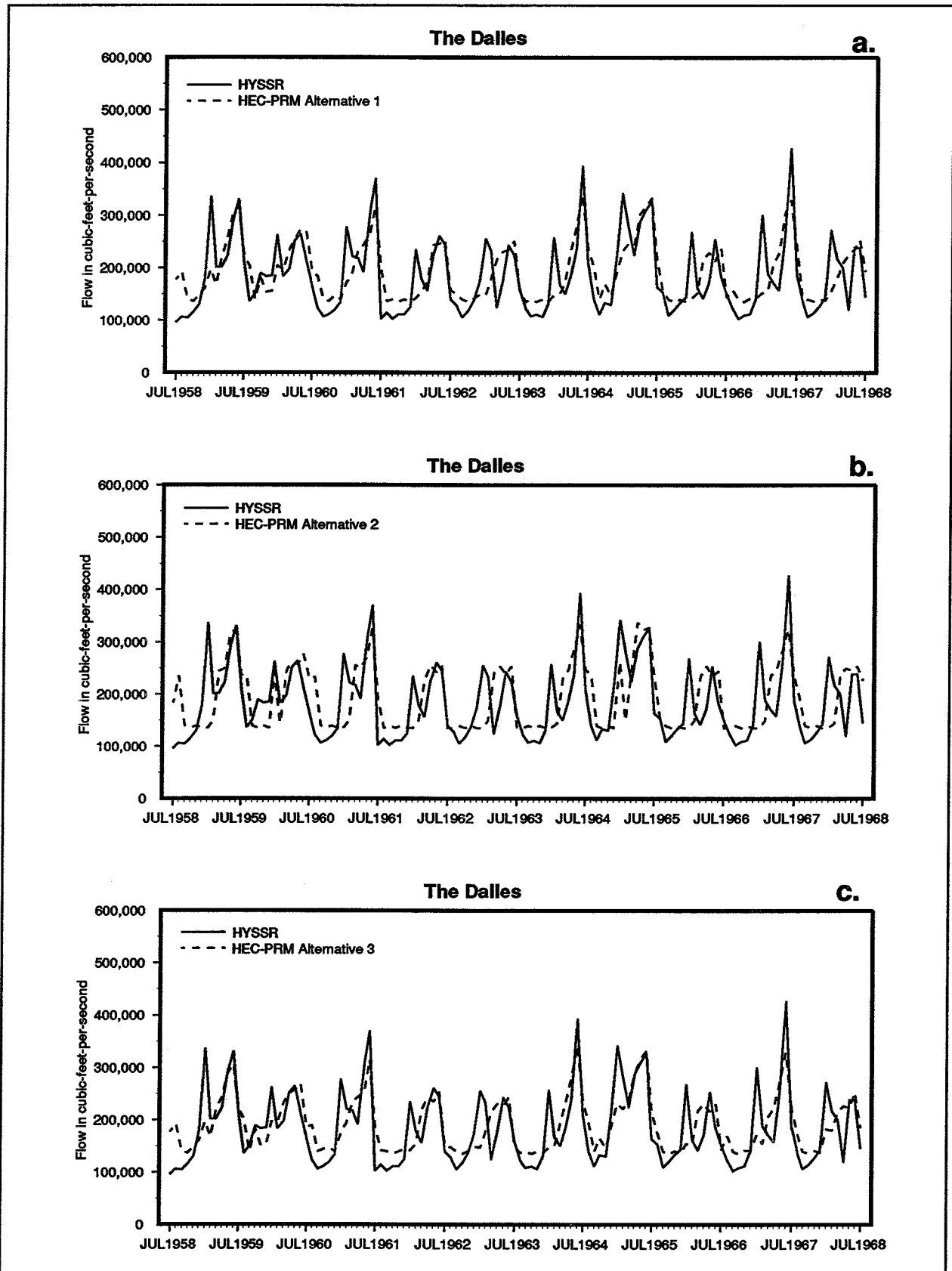
FIGURE F.19   1958 - 1968 Flow at The Dalles: HYSSR & Alternatives
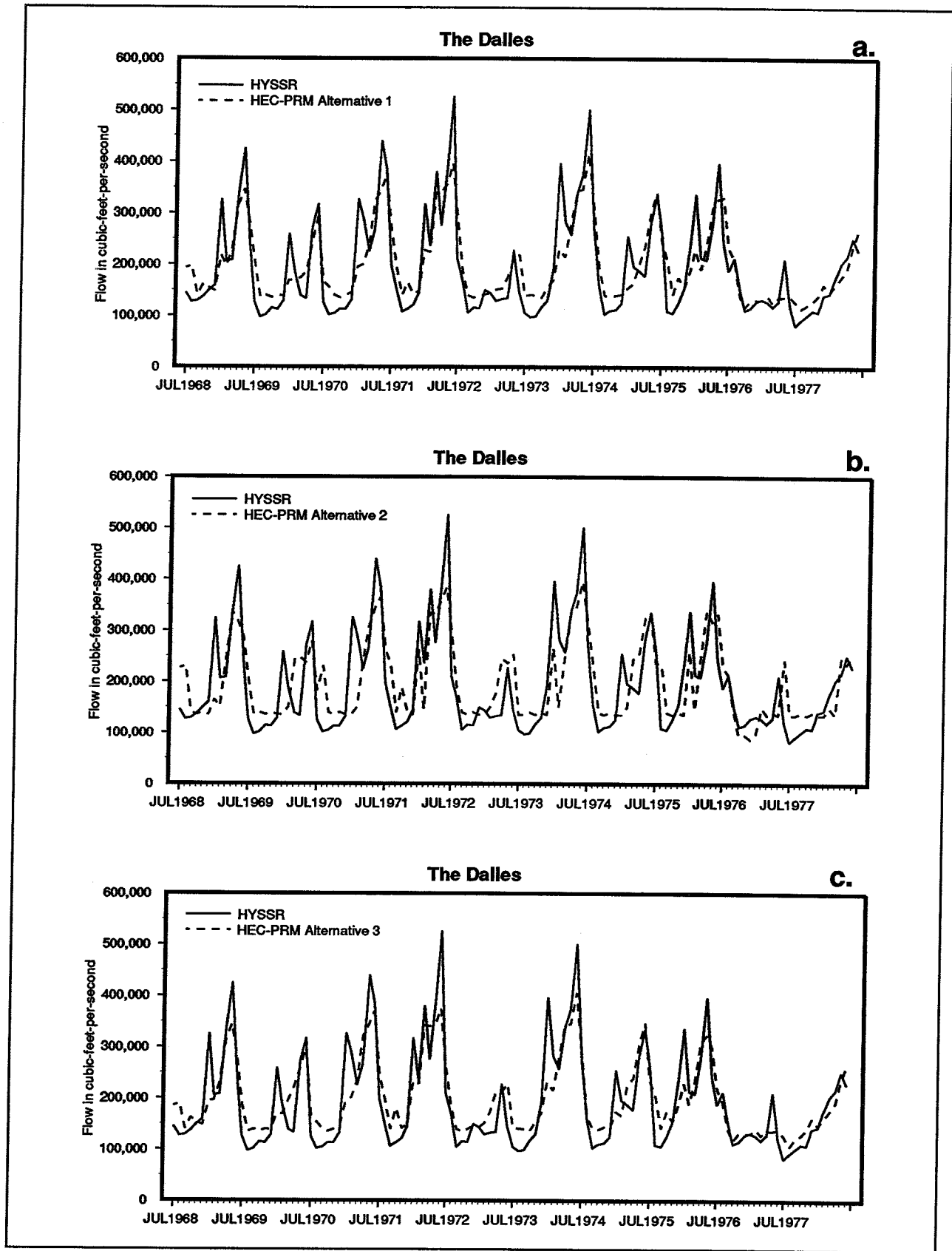
FIGURE F.20 1968 - 1978 Flow at The Dalles: HYSSR & Alternatives

Appendix G

HEC-PRM Time-series Results of Energy Production

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Appendix G

HEC-PRM Time-series Results of Energy Production

Figures

Appendix G

HEC-PRM Time-series Results of Energy Production

INTRODUCTION

This appendix shows comparisons of system energy production results for the three HEC-PRM operation analysis alternatives with HYSSR system energy production and system energy load.

The HEC-PRM results that are shown have been computed by summing energy production at all hydropower locations included in the HEC-PRM models. To provide an equivalent basis of comparison, HYSSR energy production has been computed by applying HYSSR computed flows and averaged storages to energy production functions developed by NPD. These energy production functions were the foundation for the IWR developed HEC-PRM hydropower penalty functions.

The system energy load shown was developed by NPD for HYSSR applications. It represents non-thermal system energy demands for a 1990 level of development. Included in this demand sequence is energy generated as a consequence of annual May fish releases.

System energy production and load are shown in Figures G.1 through G.5 for the entire 50-year period of analysis (1928 - 1978).
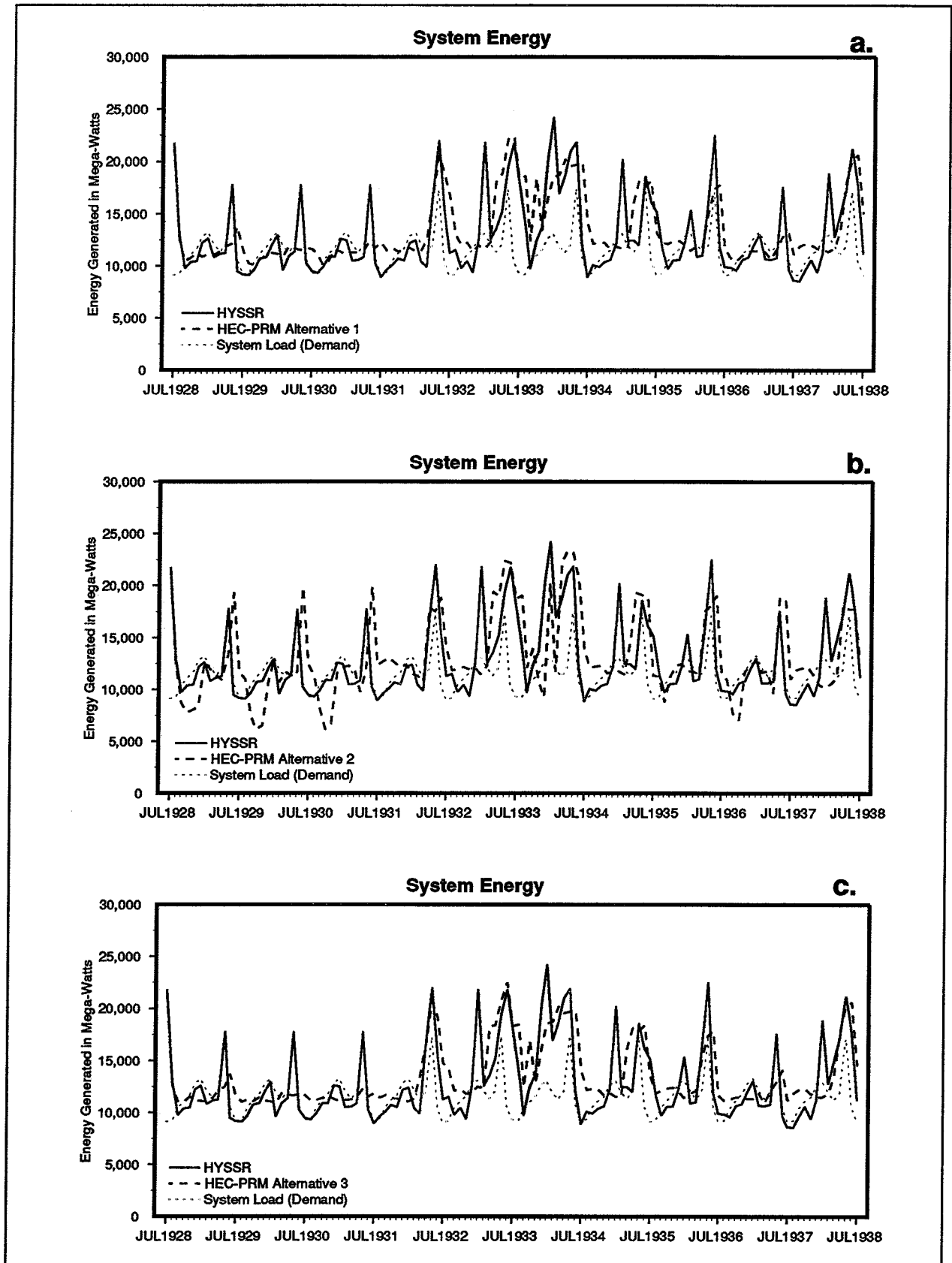
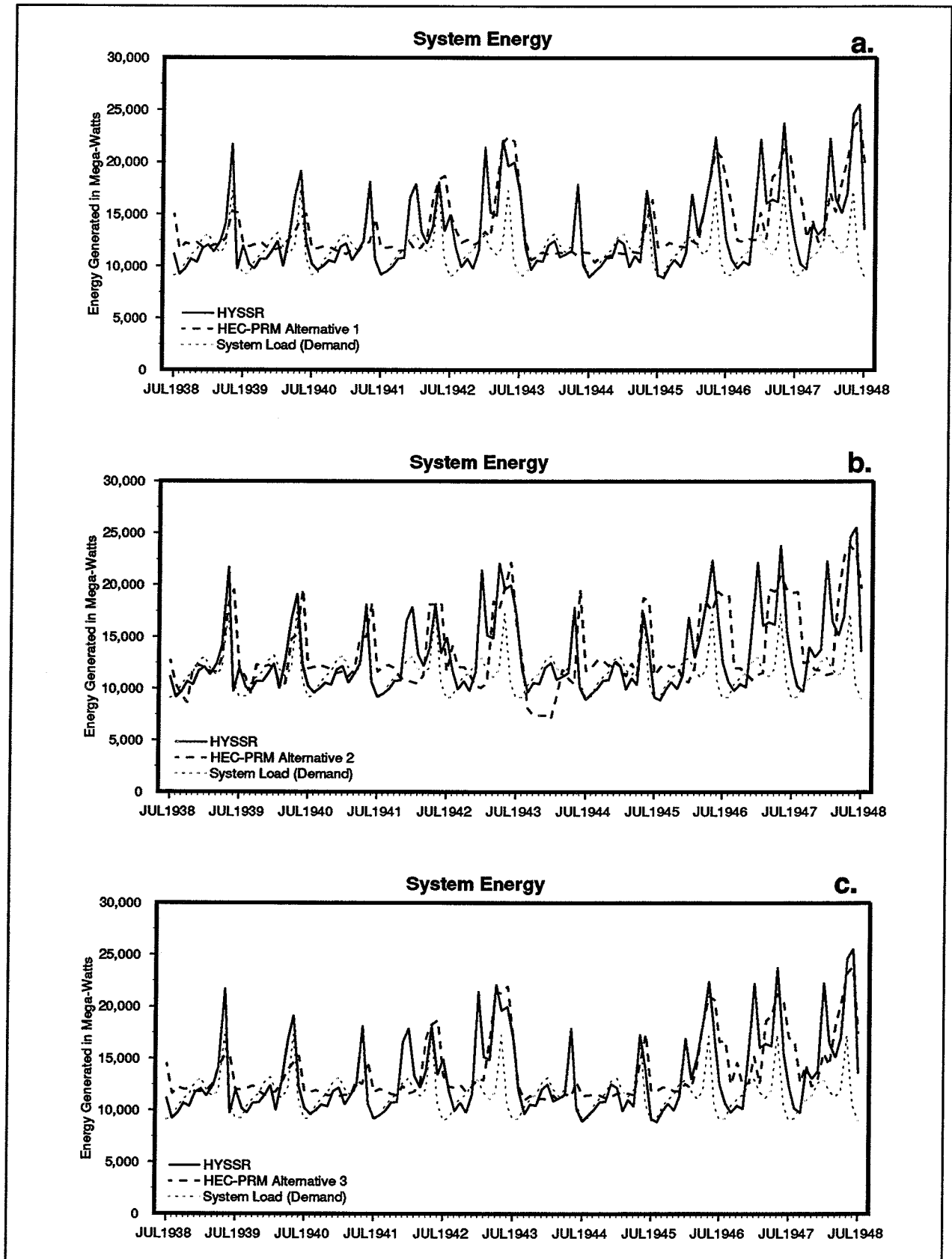**FIGURE G.1 1928 - 1938 System Generated Energy: HYSSR & Alternatives**

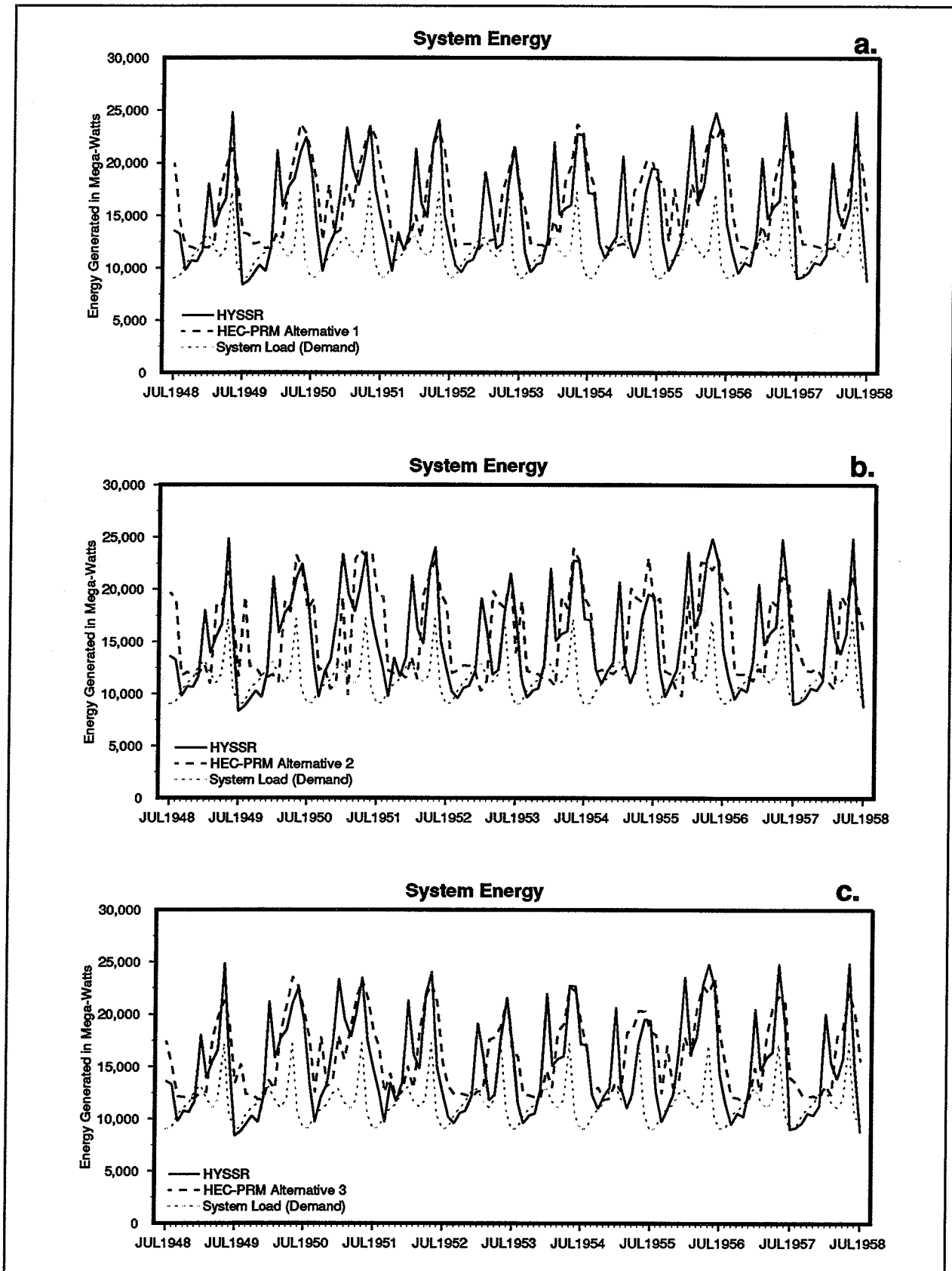**FIGURE G.2 1938 - 1948 System Generated Energy: HYSSR & Alternatives**

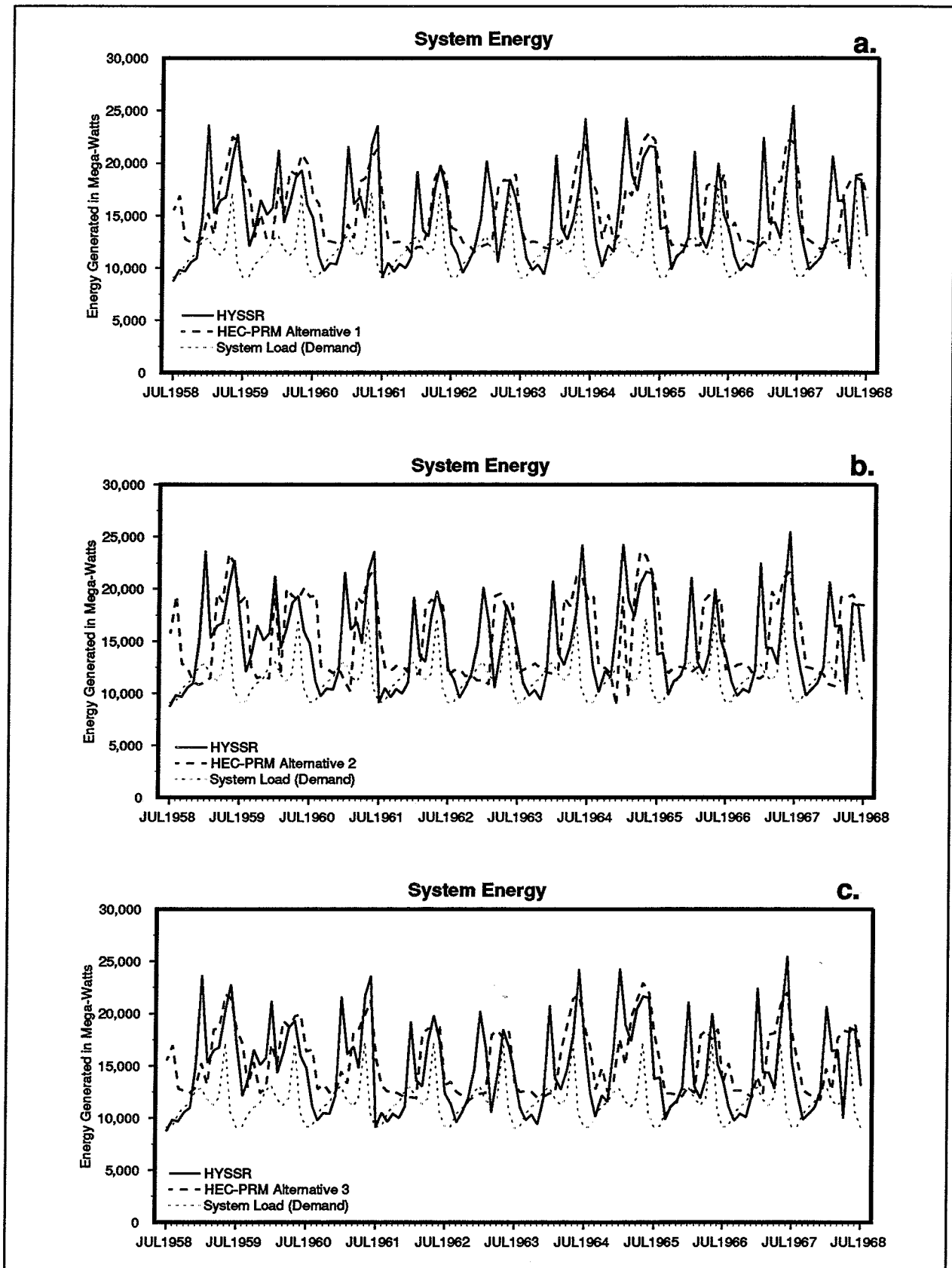**FIGURE G.3 1948 - 1958 System Generated Energy: HYSSR & Alternatives**

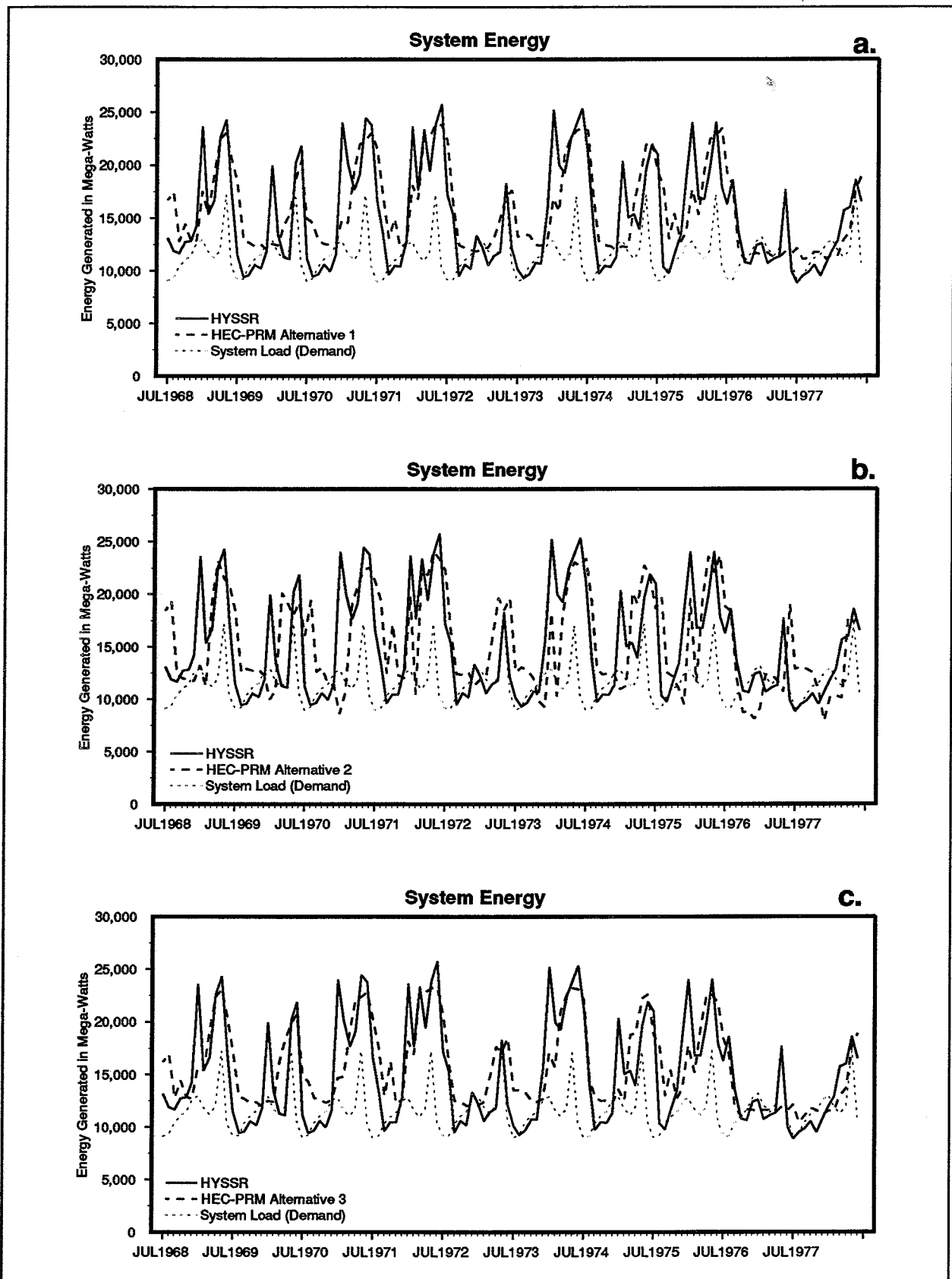**FIGURE G.4 1958 - 1968 System Generated Energy: HYSSR & Alternatives**

FIGURE G.5 1968 - 1978 System Generated Energy: HYSSR & Alternatives