US Army Corps of Engineers ®
Seattle District

TRANSMITTAL MEMORANDUM

TO: KENNETH PFLUEGER, WELLS PROJECT CHIEF ENGINEER, DOUGLAS COUNTY PUBLIC UTILITY DISTRICT
GREGG CARRINGTON, DIRECTOR OF HYDRO SERVICES, CHELAN COUNTY PUBLIC UTILITY DISTRICT

FROM: EVAN LEWIS, U.S. ARMY CORPS OF ENGINEERS, SEATTLE DISTRICT

SUBJECT: REFERRAL OF *CHIEF JOSEPH DAM GENERATION IMPROVEMENT STUDY, TURBINE RUNNER REPLACEMENT ECONOMIC EVALUATION*

DATE: 4/27/2006

Mr. Pflueger and Mr. Carrington,

Douglas and Chelan PUDs requested the enclosed report in their comments on the environmental assessment of the turbine runner replacement at Chief Joseph Dam. This version of the report has been revised to black out the portions of the report that are subject to withholding under the Freedom of Information Act and/or are prohibited from disclosure under Federal procurement statutes.

The final environmental assessment and the enclosed report have also been posted online at <http://www.nws.usace.army.mil/ers/doc_table.cfm> under "Chief Joseph Dam Turbine Runner Replacement."

Please call or e-mail me with any questions at evan.r.lewis@usace.army.mil or (206) 764-6922.

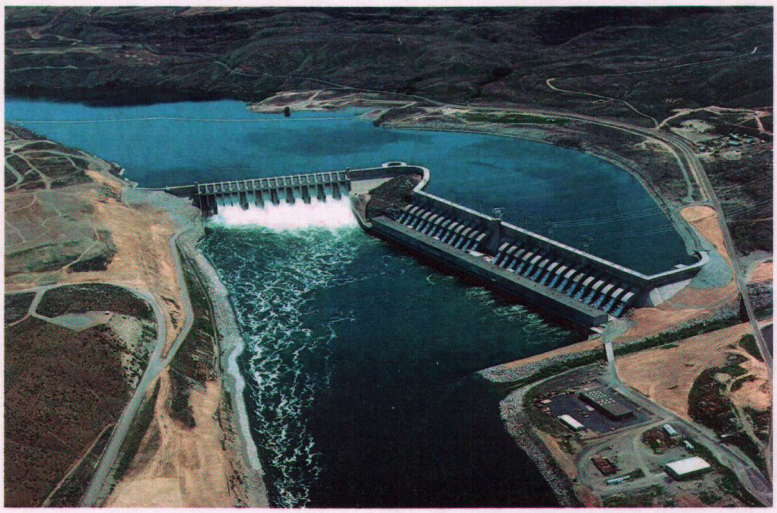
Addresses:

Kenneth Pflueger
Wells Project Chief Engineer
Douglas County PUD
1151 Valley Mall Parkway
East Wenatchee, WA 98802

Gregg Carrington
Director of Hydro Services
Chelan PUD
P.O. Box 1231
Wenatchee, WA 98007-1231

Chief Joseph Dam Generation Improvement Study

Turbine Runner Replacement Economic Evaluation



Final – January 26, 2006

Prepared by the Economic Analysis Team

for the

Turbine Analysis Review Team

BONNEVILLE POWER ADMINISTRATION

US Army Corps of Engineers ®

Executive Summary

The Federal Columbia River Power System (FCRPS) Capital workgroup chartered the Turbine Analysis Review Team (TART) in November 2002 to evaluate potential methods for improving hydropower generation benefits at the Chief Joseph Project. The team consisted of members from the Army Corps of Engineers and Bonneville Power Administration.

This task was divided into two phases. During Phase I, the team developed a list of alternatives and completed an initial screening of these alternatives using reconnaissance level costs and benefits. The Phase I report recommended three alternatives for additional analysis:

- Turbine and wetted equipment replacement or upgrade in units 1-16
- In-stream pump storage (pump back) using units 1-16
- Two-foot pool raise, thereby increasing generation head by two feet

Further discussion and management review determined that in-stream pump storage and the two-foot pool raise were not viable alternatives at this time. The majority of the benefits for in-stream pump storage could be realized by operational changes. A wide range of issues complicates the two-foot pool raise, and management deferred further study of this option at this time.

Phase II involved a detailed analysis of the potential benefits and costs of turbine runner replacement of units 1-16. This incremental analysis determined the benefits, costs, net present value, and internal rate of return that could be expected from replacing these units.

Chief Joseph Power plant includes 27 main units and 2 station service units. The original 16 units were brought online from 1955-1958. Eleven additional units, 17-27, were added from 1977-1979. The power plant has three "families" of main units. The first family, units 1-4 and 15 and 16, are identical in design and were manufactured by S. Morgan Smith Company. The second family, units 5-14, is identical in design and was manufactured by Newport News. The third family, units 17-27, was manufactured by Hitachi, but was not included in this study since they are relatively new and did not present an opportunity for replacement.

Units 1-16 were upgraded between 1983 and 1988 by rewinding the generators, replacing circuit breakers, and upgrading the transformers and ancillary equipment. There have been significant changes to the project since its original design, resulting in hydraulic changes over the last 20 years that have modified the design conditions for these turbines. These include: a 10-foot pool raise, addition of units 17-27, and a tailwater rise from the construction of Wells Dam. With these changes, units 1-16 cannot achieve nameplate capacity during high flow conditions. In addition, units 1-16 require extensive maintenance on a recurring basis to repair cavitation damage. Performance testing has

determined that there is significant degradation in the efficiency of the turbines for these units. Replacement turbine runners for units 1-16 using different design criteria would allow the full generator capacity to be reached under all hydraulic conditions

This analysis looked at replacing turbine runners for units 1-16 incrementally and assumed that replacements would be accomplished sequentially by family. The Newport News turbines were assumed to be installed first as they have the lowest efficiency and therefore the largest potential for improvement.

Recommendations

1. The recommended economic alternative is to replace the runners on the ten Newport News turbine units (units 5-14). The incremental benefits for the remaining six units do not justify their replacement at this time. Replacing the Newport News units has an expected Internal Rate of Return of 22.1% and a net present value of $28.2 million based on current (2005) dollar levels with an assumed inflation rate of 3%.

2. The procurement contract should be structured for the acquisition and installation of all Newport News units in a single contract, rather than a contract to replace one with options for the rest.

3. In addition, it is recommended that the procurement contract include an option for the acquisition and installation for the six S. Morgan Smith turbine units. After the initial contract is awarded and turbine prices and guaranteed turbine performance is received for the first ten units, the economics of replacing the turbine runners should be re-evaluated.

Expected Benefits of Turbine Runner Replacements

	Total	
Turbine Runners Replaced	10	16
Internal Rate of Return (IRR)	22.1%	18.2%
Net Present Value (NPV) ($Million)	28.2	20.6
Benefit to Cost Ratio (B/C)	1.84	1.42

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1.0 Introduction

1.1 Background

The Chief Joseph turbine runner replacement analysis is a collaborative effort between Bonneville Power Administration (BPA) and the Corps of Engineers (COE). Collaboration between BPA and the COE is critical because each organization has a somewhat different approach to assessing the viability of hydropower investments. The overall methodology for analyzing hydropower investments is evolving in the Northwest due to these differences in agency perspective and the way investments are funded. Historically, major hydropower analysis work was funded through congressional appropriations. This has changed. BPA is now authorized to directly fund capital hydropower improvements, including participating on evaluations to justify such investments. A collaborative investment evaluation approach insures the objectives of both agencies are met.

The purpose of this report is to present the results of Phase II analyses by the joint BPA/COE Turbine Analysis Review Team (TART) of the benefits expected for turbine runner replacements at the Chief Joseph Project and the recommended investment decision.

The Chief Joseph Project and Rufus Woods Lake are located in north central Washington 545.5 miles upstream from the mouth of the Columbia River. The Chief Joseph powerhouse includes 27 main units and 2 station service units. The original 16 units were brought online from 1955-1958. The family of units 1-4 and 15 and 16 are identical in design and were manufactured by S. Morgan Smith Company. The family of units 5-14 are identical in design and were manufactured by Newport News. Eleven additional units, 17-27, were added from 1977-1979, and were manufactured by Hitachi. Generators for units 1-16 were upgraded between 1983 and 1988 by rewinding the generators, replacing circuit breakers, and upgrading the transformers and ancillary equipment. The existing generators for units 1-16 at Chief Joseph now have a capacity of 88.3 MW each. The pre-1987 capacity of these generators was 64.0 MW. The current total generator capacity for the plant is 2,614 MW (16 @ 88.3 MW, 11 @ 109.3 MW).

There have been significant changes to the project since its original design, resulting in hydraulic changes over the last 20 years that have modified the design conditions for these 16 turbines. These include: a 10-foot pool raise, addition of units 17-27, and a tailwater rise due to the construction of Wells Dam downstream. With these changes, units 1-16 cannot achieve nameplate capacity during high flow conditions. In addition, these units require extensive maintenance on a recurring basis to repair cavitation damage. Performance testing has determined that there is significant degradation of the efficiency of the turbines for units 1-16. Replacement turbine runners for units 1-16 using different design criteria would allow the full generator capacity to be reached under all hydraulic conditions.

The FCRPS Capital workgroup chartered the TART in November 2002 to evaluate potential methods for improving hydropower generation benefits at Chief Joseph Dam. The team consisted of members from the Army Corps of Engineers and Bonneville Power Administration.

Phase I of the TART process was to develop a list of proposed alternatives to improve the hydropower generation benefits and do an initial screening of the alternatives to determine which alternatives should be carried forward. Results of the Phase I screening showed that the following three alternatives provided sufficient benefits to justify additional analysis:

- Turbine and wetted equipment replacement or upgrade in units 1-16
- In-stream pump storage (pump back) using units 1-16
- Two-foot pool raise, thereby increasing generation head by two feet

Further discussion and management review determined that in-stream pump storage and the two-foot pool raise were not viable alternatives at this time. The majority of the benefits for in-stream pump storage could be realized by operational changes. A wide range of issues complicates the two-foot pool raise, and management deferred further study of this option at this time.

This report documents Phase II of the TART process and provides a detailed analysis of the potential benefits and costs of replacing turbine runners for units 1-16. This analysis looked at the incremental benefits and costs and the internal rate of return that could be expected from replacing these runners.

1.2 Process Overview

This report was prepared by the Economic Analysis Team (EAT) (see Table 1-1), which was formed at the beginning of Phase I and has worked under the charter of TART. EAT began by identifying an appropriate set of assumptions and tools to be used in this evaluation. In an uprate study done for the McNary Project, two distinctly separate approaches were used by the COE and BPA. The results of these two approaches provided similar recommendations on how to proceed with the McNary uprate. Based on lessons learned from the McNary study, EAT decided to develop and use a hybrid approach that combined the strengths of both the COE and BPA approaches used in the McNary analyses and eliminated some of the redundant work performed in that study.

Table 1-1 Economic Analysis Team Members

Team Member	Organization
Jack Allison	BPA – Federal Hydro Projects
Mike Egge	COE – Hydropower Analysis Center
John Johannis	COE – Hydropower Analysis Center
Tim Kuhn	COE – Hydropower Analysis Center
Kamau Sadiki	COE – Hydropower Analysis Center
Philip Thor	BPA – Federal Hydro Projects
Dan Watson	COE – Hydroelectric Design Center
Rick Werner	COE – Chief Joseph Project

Section 2406 of the National Energy Policy Act of 1992 (P.L. 102-486) provided authority for BPA to provide direct funding for capital investments at COE power plants. In 1994, a direct funding Memorandum of Agreement (MOA) was signed to allow BPA to directly fund capital investments at COE projects rather than using appropriated funds, and in 1997 the COE and BPA signed another MOA to directly fund the power portion of O&M expenses. During the July 1998 to 1999 period, the Northwestern Division (NWD) coordinated with HQUSACE on guidance for economic analysis for BPA funded investments. During the 1999 to 2000 period, a joint BPA/COE team was established to develop proposed guidance for direct funded investments at COE facilities, and a policy and procedure document - the Capital Investment Decision and Analysis Guidance (CIDAG) - was developed by this team. In 2001, Final guidance was issued for implementation of CIDAG throughout the NWD. BPA has accepted CIDAG as the basis for evaluating investments at COE facilities and this report is consistent with the requirements defined in CIDAG.

A key objective of BPA when evaluating alternative hydropower investments is to determine the project's financial viability. BPA requires the project to meet an Internal Rate of Return (IRR) equal to or greater than 13% based on the projected stream of benefits and costs including inflation considered over the evaluation period.

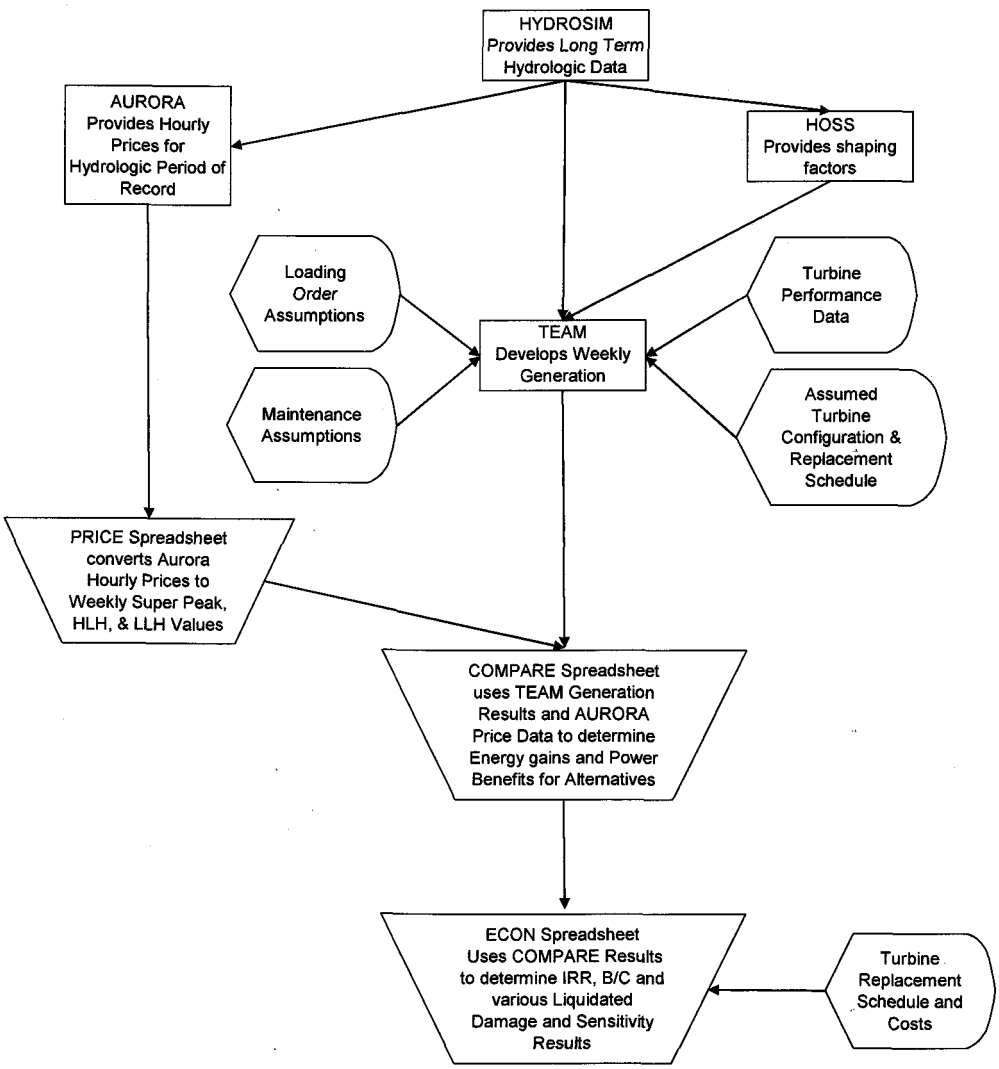
The COE has traditionally used a broader perspective for evaluations on the basis of national economic development (NED) benefits. For a COE evaluation, the FY 2005 federal water resources discount rate of 5.375% is applied to the un-inflated stream of benefits and costs in order to identify investments with benefit-to-cost ratios (B/C) greater than or equal to 1.0 and which maximize net benefits. The alternative that maximizes net benefits is typically identified as the recommended plan. The Chief Joseph turbine runner replacement economic analysis considers the needs of both BPA and the COE.

Key attributes used in the economic analysis were:

- A detailed energy production model that included turbine performance, maintenance schedules, and unit loading order
- Measured existing turbine performance and expected performance for replacement turbines
- 50-year simulated operation with resultant hydrologic flow
- Energy generation separated into three parts: super-peak, heavy load hour (on-peak), and light load hour (off-peak)
- Power price forecasts over the long-term hydrologic period broken into super-peak, heavy load hour (on-peak), and light load hour (off-peak)
- Unit maintenance and loading orders to reflect turbine runner replacements
- Incremental unit analysis
- 35-year investment life (beginning in FY 2005)
- 3% inflation rate on costs
- 5.375% interest during construction (BPA assumption)
- Design, purchase, manufacturing, and installation cost estimates
- 13% discount rate
- 3% inflation of energy values
- No cost contingencies

The process consisted of starting with a long-term hydrologic record (50 years), breaking this record down to weekly periods, with each week further broken down into three sub-periods - super-peak hours, heavy load hours (on-peak), and light load hours (off-peak) using system shaping factors. Using this weekly hydrologic data, generation is determined for each sub-period based on assumptions about maintenance schedules, loading orders, and turbine performance curves. Hourly price data is then used to convert this generation data into monetary values and the delta between the base (existing conditions) and various alternatives consisting of different combinations of turbine runner replacements. Using an assumed construction schedule and turbine cost data, the IRR, NPV, and B/C ratio as well as various sensitivity results and potential values for liquidated damages are then calculated. The relationship between the various tools and models used is shown in Figure 1-1.

Figure 1-1 Tools Used in the Economic Evaluation



2.0 Turbine Runner Replacement Options and Costs

The existing Chief Joseph Powerplant cannot reach its installed nameplate capacity of 2,614 Megawatts under normal operating conditions. Units 1-16 turbines do not produce enough horsepower to allow the rewound generators to reach their nameplate capacity at the original rated hydraulic conditions.

During the last 20 years the project has undergone significant hydraulic alterations as a result of raising the maximum allowable pool 10 feet in elevation, the addition of units 17-27, and a tailwater rise due to the construction of Wells Dam downstream.

Recent turbine performance testing for both families of older units has shown that degradation in both efficiency and capacity has occurred.

These facts and recent demonstrated technology advances in the field of turbine design provide an incentive to replace the runners on the older units. Replacement of the turbine runners for units 1-16 will allow the plant to produce the installed nameplate capacity and increase annual energy production.

To help study the economic benefits of this replacement, design criteria were laid out to show expected performance for replacement with new turbine runners. Part of this design criteria is the determination of the design head and the rated head of the new turbines.

2.1 Design Criteria

There are three families of units at Chief Joseph. The scope of this report is on the two older families, units 1-16, manufactured by S. Morgan Smith Co. and Newport News Co.

2.1.1 Determination of Design Head

The design head is the head at which the new runners will operate most efficiently. Three methods were used to determine the design head for the new turbine runners:

Average Project Head: This method determines the average head at the project commonly called the 50% duration head. The 50% duration gross head for Chief Joseph occurs at 171.3 feet.

Tailwater Curve: The tailwater curve is a graph showing the tailwater as a function of project discharge. Using this curve with the 50% duration project discharge, 112,300 cfs, a design gross head of 171.2 feet is determined.

Turbine Runner Output: This method determines the design head by finding the head at which the 50% duration on-line turbine runners produces the 50% duration project discharge of 112,300 cfs. This gross head occurs at 171.3 feet.

The design gross head was determined to be 171.3 feet. Since the head loss at best efficiency point for these turbine runners is about 1.3 feet, the design net head is 170.0 feet.

2.1.2 Determination of Rated Head

The existing turbines 1-16 and 17-27 develop their respective rated head capacity (generator MCDR (Maximum Continuous Duty Rating) at 100% gate) at different net heads because of design differences and hydraulic head loss differences. The two turbine families that make up units 1-16 develop their rated gross heads between 171.0 and 172.5 ft. Units 17-27 attain their rated head at about 167.0 ft. Since the plant is operated under a single gross head, it is desirable to have all units reach rated capacity near the same gross head while operating in the normal pool operating range.

With this in mind, a spreadsheet was developed using performance from current unit tests. A choice was made to assume 25 units would be operating at full gate to determine the rated condition. Rated head is the lowest head at which power output of the turbines operating at full gate reaches the generator limit. The lowest gross head that produces generator limit at full gate for these 25 units is about 167.0 feet.

Rated heads for the current turbines and the proposed new turbines are shown in Table 2-1.

Table 2-1 Rated Head

Gross Head at which units 1-16 and 17-27 develop Generator MCDR

	Units 1-4, 15, 16 (ft GH)	**Units 5-14 (ft GH)**	**Units 17-27 (ft GH)**
Existing Units 1-16 and 17-27	171	172.5	167
New Units 1-16 and 17-27	167	167	167

2.2 Turbine Runner Performance Curves

This section describes the three families of units at Chief Joseph, and the calculations of the expected efficiencies for the new runners.

2.2.1 S. Morgan Smith (Units 1-4, 15, 16)

Existing performance was determined from the September 2002, unit 15 performance test and the 1954 model test. Information from these two sources was used to develop existing prototype performance for every 5 feet over the operating range. These curves

were adjusted to higher efficiency and higher power for the expected new runners. The expected efficiency for the new runners was set at 94% at the design gross head of 171.3 feet. These curves are shown in Appendix A.

2.2.2 Newport News (Units 5 to 14)

Existing performance was determined from the December 2002, unit 11 performance test and the 1951 model test. Information from these two sources was used to develop existing prototype performance for every 5 feet over the operating range. These curves were adjusted to higher efficiency and higher power for the expected new runners. The expected efficiency for the new runners was set at 94% at the design gross head of 171.3 feet. These curves are shown in Appendix A.

2.2.3 Hitachi (Units 17 to 27)

Existing performance was determined from the December 1990, unit 18 performance test and the 1985 model test. Information from these two sources was used to develop existing prototype performance for every 5 feet over the operating range. These curves are shown in Appendix A and were used for plant operating conditions.

2.3 Expected Project Capacity Improvements

Procurement and installation of new Francis runners, which would be designed for the currently anticipated operating conditions, will take advantage of new turbine advances. Shaft stress analysis has indicated that new replacement runners could be operated up to 120,250 hp (88.27 MW) without shaft modification. This would allow the full generator capability to be used, and would result in an increased powerplant capacity of 92 MW if installed in all 16 units. Potential project capacity gains and energy gains for replacing both families of units are shown in Tables 2-2 and 2-3.

Table 2-2 Expected Project Capacity Improvement for Units 1-16

	Turbine (hp)		Generator (MW)	
	Units 1-4, 15, 16	Units 5-14	Units 1-4, 15, 16	Units 5-14
Capacity of existing runners at 167.0 feet Gross Head	115,225	114,332	84.69	84.07
Capacity of replacement runners at 167.0 feet Gross Head	120,250	120,250	88.27	88.27
Improvement in capacity with runner replacement	5,025	5,918	3.58	4.20

Table 2-3 Expected Project Efficiency Improvement for Units 1-16

	Best Turbine Efficiency Point at Design Head 171.3 ft. Gross Head (%)		Turbine Efficiency at Rated Conditions, 167.0 ft Gross Head at Generator MCDR (%)	
	Units 1-4, 15, 16	Units 5-14	Units 1-4, 15, 16	Units 5-14
Existing units 1-16	89.7	88.9	less than 83.0	less than 83.0
Replacement runners in units 1-16	94.0	94.0	89.5	89.4
Improvement in efficiency with runner replacement	4.3	5.1	greater than 5.5	greater than 6.4

2.4 Costs

This section summarizes the costs of replacing the runners of units 1-16 at Chief Joseph dam. A subteam with members from BPA and the Corps' Hydroelectric Design Center estimated the costs for each family of units. The basis for the cost estimates is the Bid Schedule that will be part of the contract solicitation. The bid schedule is comprised of two parts: the first part includes the base items (i.e., those items that will be accomplished for every unit) and the one time costs (i.e., mobilization). The second part is optional items that may be accomplished by the contractor as a result of tests or inspections. Using the costs from recent turbine runner replacement contracts, the cost for each contract item was estimated. Additionally, the frequency of using an optional item was estimated. Using the cost of the optional item and the frequency of use, a cost for that item was calculated.

2.4.1 S. Morgan Smith Units 1- 4, 15, 16

The total for these units is the sum of the one-time costs, the product of 6 times the base items, and the product of 6 times the optional items. [redacted]. The detailed cost estimate for replacing the runners is in Appendix D.

2.4.2 Newport News 5-14

The total for these units is the sum of the one-time costs, the product of 10 times the base items, and the product of 10 times the optional items. [redacted]. The detailed cost estimate is in Appendix E.

2.4.3 Related Overhead Costs

The cost subteam used the project schedule (Appendix C) to estimate the costs for supporting the installation of the turbine runners. The cost elements include economic evaluation, engineering and design, engineering during construction, contracting, project management, contract supervision and administration, and project support. [redacted] The detailed cost estimate is in Appendix F.

2.4.4 Reduced Maintenance Costs

Runner replacement with a stainless steel runner that meets the cavitation requirements will result in a maintenance schedule like that of the Hitachi turbines. Currently each Newport News and S. Morgan Smith turbine requires maintenance for cavitation repair once every 4 years with material and labor costing $12,500 during an 8-week outage. Since four runners are completed each year, the average annual maintenance cost is about $50,000. The Hitachi turbines require no cavitation repair and each is taken out of service for four weeks every 5 years. The benefits of a reduced outage and an increased period between maintenance outages are captured in TEAM, as described in section 4.2.1.3. The avoidance of the yearly labor and material cost is added as a benefit in the economic model.

2.4.5 Outage Costs during Construction

Outage costs are valued as described in section 6.3. Durations and timing are from the project schedule for the economic model. Outage costs from TEAM are an annual value and are prorated by fiscal year as a ratio of the total outage to the month out in that fiscal year. For concurrent two unit outages the value is split equally between the units. Outage costs inflated, by fiscal year and unit, are summarized in Table 2-4.

[redacted]

[redacted]

2.4.6 Cost Summary

Total incremental inflated costs, including outage costs and Interest During Construction (IDC) that is used for the incremental economic analysis are shown in Table 2-5.

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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3.0 System Operation and Streamflow Regulation

3.1 Project Operation

The Chief Joseph project is operated to meet multiple uses. The specific operating requirements stem from a variety of sources, including original project authorizing documents, project operating guides or plans, Biological Opinions related to the Endangered Species Act listings, and from operating histories and experience. While the project does not have many requirements from the 2000 Biological Opinion issued by the National Marine Fisheries Service in December 2000 and the subsequent Updated Proposed Action issued in 2004, its operation is directly affected by the ESA requirements imposed on the other projects and the system as a whole.

Chief Joseph is a run-of-river project with a small amount of pondage that is operated to pass inflows on a daily basis. The original project authorization allowed the project's forebay elevation to be regulated between 930 to 956 feet above sea level. However, a more restrictive requirement is now in place, specifically requiring the project to operate in a forebay elevation range of 950 to 956 feet. Grand Coulee Project is immediately upstream: it is a storage project and thus capable of regulating flows over a broad period of time (i.e., it does not need to pass inflows), and has total powerhouse flow capacity that is significantly higher than Chief Joseph Powerhouse. In one sense, Chief Joseph provides flow re-regulation of discharges from Grand Coulee into Chief Joseph reservoir. The flexibility in the Chief Joseph forebay allows for higher inflows into the reservoir, which are above the Chief Joseph Powerhouse discharge capacity. If the project receives high inflows, a portion of them will be stored and then later released when inflows from Grand Coulee are lower, thereby restoring forebay elevations.

3.2 System Operation Models

Two system operation models are generally used by the Corps and BPA within the FCRPS to simulate river flows. Both models produce similar time series flow data based on historical water records while incorporating present day operating requirements at all regulated projects. The Hydro System Seasonal Regulation Program (HYSSR) model is used by the COE, while HYDROSIM is used by BPA. For this analysis, only flow data from the HYDROSIM model was used. The following section describes the HYDROSIM model.

3.2.1 HYDROSIM

The Hydro Simulator Program, HYDROSIM, was developed by BPA in 1990-91 and evolved from earlier programs called HYDRO2 and HYDRO6, which were written in the 1960s. Like HYSSR, HYDROSIM simulates the operating characteristics of the Northwest hydro system under varying load and flow conditions, over an extended

period. HYDROSIM uses many of the same inputs that HYSSR uses and is structured in an identical fashion. It is a sequential stream flow routing model, with 14 time periods, and it uses 1990 Level Modified Stream flows. It incorporates all operating requirements stemming from the Pacific Northwest Coordination Agreement, Columbia River Treaty, and the Biological Opinions. However, HYDROSIM simulates only a 50-year water record from 1929 through 1978, and BPA develops its own forecast of future loads and other resources for input to HYDROSIM. HYDROSIM has two simulation modes – fixed mode and proportional draft. In the fixed mode, the modelers specify the operation in each time period for all or some of the projects in advance. Water storage is drafted or filled as specified unless constrained by physical or operational limits. The model proceeds downstream and once the operation is set, flows, generation, and other project outputs are calculated. In the proportional draft mode, HYDROSIM simulates operations by drawing system reservoirs down to "energy content curves" to meet firm Pacific Northwest loads and to produce secondary or surplus energy for sale. If the system cannot meet the firm load, then all projects are drafted proportionally to a series of critical rule curves (or beyond) until the load is met, the reservoirs go empty, or they reach physical or operational limits. With the Biological Opinion, operating limits or requirements exist for most Federal projects and for most, if not all, time periods. Most HYDROSIM studies use a combination of fixed and proportional draft modes.

Like HYSSR, HYDROSIM checks operating requirements against the resulting flows and reservoir elevations. There are 10 "flags" in the program that alert the modeler that a target operation was not reached and that adjustments to the simulation are needed. Results from the HYDROSIM model have been shown to be similar to those produced by the HYSSR model. Therefore, for this analysis only one set of results was used, namely those from the HYDROSIM model.

3.2.2 The Hourly Operation System Simulator (HOSS)

The HOSS model simulates:

- The hourly operation of federal hydro resources to meet the hourly hydro load, project constraints, and daily forebay elevation targets, such that heavy-load-hour generation is maximized given the objectives of the operation.
- The federal hydro system's response to hourly load shapes without human intervention.
- Fish spill at federal projects as described by the Biological Opinion.

HOSS shapes generation that is not specific to a project, but is representative of the regulated Columbia River projects. It incorporates all of the physical and operational requirements for the federal projects identical to that in HYDROSIM and HYSSR, but includes short-term (i.e., hourly) rates of change limitations and/or requirements necessary for simulating hourly time periods. It simulates four weeks of 24-hour days,

for a total of 672 hours per month. HOSS can simulate the entire historical water record. It is typically used in one of several different modes.

In one mode, HOSS uses HYDROSIM as input to examine seasonal planning over multiple water conditions. HOSS takes the HYDROSIM starting conditions for forebay elevations (i.e., storage content) and project flows at the beginning of each month. The next month's condition from HYDROSIM is used as a target for HOSS to meet, if possible, through hourly shaping of project flows. The hourly flows result in hourly generation and spills. In essence, HOSS takes the average monthly parameters for each project and gives them an hourly shape within the month.

In another mode, HOSS can perform daily planning to develop project discharge targets for each hour of the current day. The hourly operation uses these daily planning targets to simulate the operation of each project within its operating constraints. HOSS has logic that can simulate federal non-firm transactions that will adjust the hydro load on each hour in response to the hydro conditions.

For this analysis, HOSS was used in the seasonal planning mode. The hourly shapes for each month and water year were reduced to a set of factors for specific hourly time periods during the week. Three factors were determined. One factor characterizes the generation that is expected to occur during the super-peak hours of each month. There are six hours per weekday, for a total of 30 hours per week, which are considered super-peak hours. The average monthly generation is multiplied by this factor to estimate the average super-peak generation for that month. For example, a factor of 1.5 means that super-peak hour generation is 1.5 times the monthly average generation for the particular month, as determined by HYDROSIM.

Two similar factors are used for heavy load hours and light load hours. There are 66 heavy load hours per week (16 hours per day for weekdays and Saturday minus super-peak hours) and 72 light load hours (8 hours per day for weekdays and Saturday and 24 hours for Sunday). Weighing the generation for each period by the number of hours in the period will result in the average weekly generation. These factors simply divide the average monthly generation into three levels represented by the types of hourly loads experienced by the system. For this study, these factors were applied to weekly flows. The average weekly shaping factors used in this study are shown in Figure 3-1. The figure begins with week one on August 1.

[redacted]

4.0 Energy Production

Energy production for Chief Joseph project is primarily driven by Columbia River system operations as described in the previous section. Energy production and generation shape at the project are highly dependent on several assumptions specific to Chief Joseph powerplant. In addition to system operations, some of the key factors that influence benefits from turbine runner replacement include assumptions about loading order, the amount of peaking that occurs at Chief Joseph powerplant, and changes in maintenance that will result from turbine runner replacements.

4.1 Operational Models for Energy Production Evaluation

In a previous study done for McNary Project, two separate models were used to evaluate energy production. One model was the FORTRAN-based Energy Hydropower Allocation (HALLO) Model and the other was a spreadsheet-based model known as the McNary Uprate Study Team (MUST) VI Spreadsheet Tool. Both models determined generation over a period (50 to 60 years) with each year broken into 14 sub-periods (12 months with April and August each split into two periods). Each of these models had its own particular strengths. HALLO provided 1) a more detailed representation of turbine performance curves on a unit-by-unit basis, 2) the ability to define specific loading orders, and 3) a specific unit-by-unit maintenance schedule. While HALLO determined average monthly generation, MUST incorporated the ability to break monthly generation into three sub-periods: Super Peak (SP), Heavy Load Hour (HLH), and Light Load Hour (LLH) which could be valued at the appropriate price levels. Because MUST was spreadsheet-based it was relatively easy to use and process the output as well as being extremely portable.

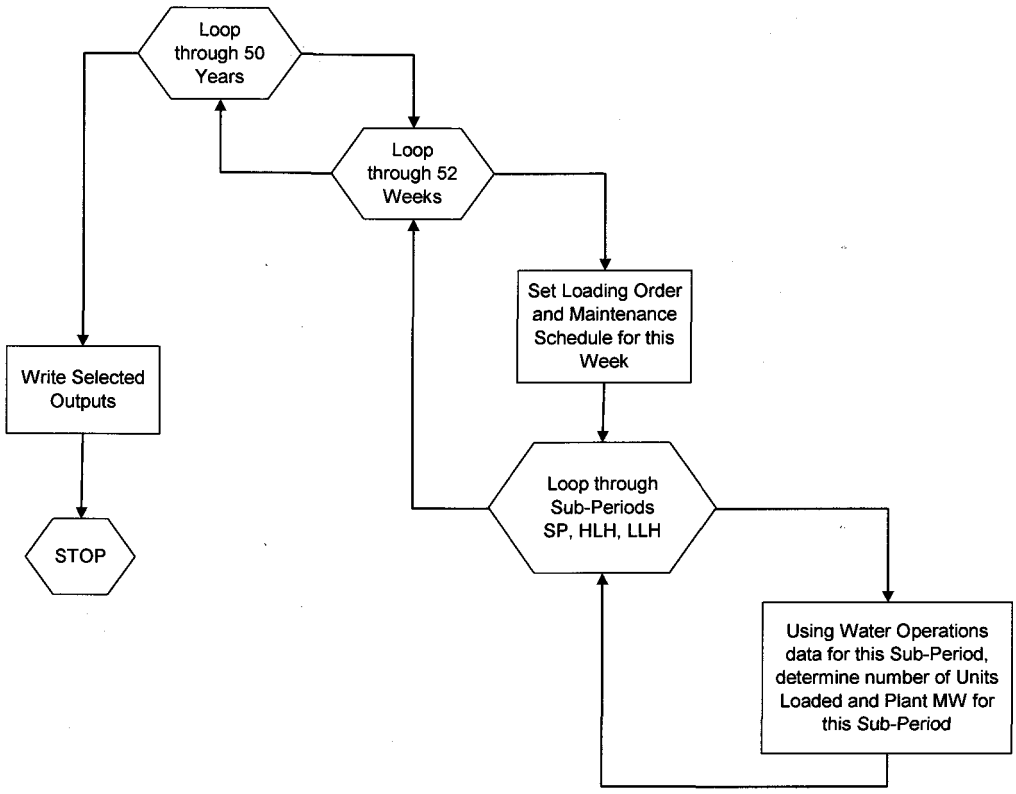
Based on lessons learned in the McNary Uprate Study, the EAT decided to develop and use one model that built on the strengths of both HALLO and MUST. A new model, the Turbine Energy Analysis Model (TEAM) was developed for use in the Chief Joseph study. TEAM is an Excel spreadsheet that uses the same sub-periods as MUST and uses Visual Basic for Applications to incorporate much of the HALLO logic.

4.2 TEAM Overview, Inputs, and Outputs

As discussed above, TEAM was derived from two models used in the MUST study. In addition, TEAM was developed to allow each year to be broken into 52 weeks rather than just the 14 periods used in the McNary Study. In addition, each week is further broken into the three sub-periods used in MUST (SP, HLH, and LLH). A simplified logic diagram is shown in Figure 4-1. All inputs are defined within the TEAM spreadsheet. When executed, TEAM loops through all years in the long-term hydrology (50 years used in this study); within each year TEAM then loops through each week, and within each week TEAM loops through the three sub-periods starting with super peak, then HLH, and

finally LLH. For each sub-period, TEAM uses the defined flow and head for that sub-period and loops through the units based on the loading order specified for that week while checking the maintenance schedule for unit availability. It loads as many units as needed to fully use the sub-period flow. Using performance curves specified for each unit, units are first loaded at their best efficiency point and if after all units are loaded there is flow remaining, units are then loaded up to their generator limit. For the first two sub-periods, if flow remains after all units have been loaded up to their maximum limit, remaining flow is moved to the next sub-period (from super peak to heavy load and from heavy load to light load). For the last sub-period (LLH), if flow remains, all sub-periods are set to the weekly average flow and any unused flow (spill) is assumed to occur in all sub-periods. After all the years are completed, depending on selected output, power generation, total flow, power flow, unused power flow, gross head, tailwater, and overall efficiency are output for each sub-period to the TEAM spreadsheet. In addition, if selected, unit-specific output is available for each sub-period. A more detailed description of TEAM logic is available in Appendix B – TEAM. A brief description of TEAM inputs and outputs follows.

Figure 4-1 TEAM Logic Flow



4.2.1 TEAM Inputs

4.2.1.1 Turbine Performance Data

TEAM requires detailed information for combined turbine and generator performance for each type of unit included in the evaluation. For each unit TEAM requires four polynomial equations (up to 3rd order) that are each a function of gross head. These are Power (MW) at Best Gate (PBG), Power (MW) at Full Gate (PFG), Efficiency (%) at Best Gate (EBG), and Efficiency (%) at Full Gate (EFG). For each unit the generator upper limit in MW is required. In addition, four points (starting head, starting MW, ending head, and ending MW) are included to define an upper cavitation limit. This data is included in the TEAM spreadsheet on worksheet "Unit Performance." This sheet also includes the total number of units for the Powerplant (27 for this study) and the number of different types of units (five used in this study). The unit type for each unit is assigned on worksheet "Unit Operations." The performance curves used in this study for Chief Joseph are shown in the Figures 4-2, 4-3, and 4-4. Additional information concerning the performance equations is contained in Appendix A - Turbine Performance Information.

[redacted]

[redacted]

Figure 4-4 TEAM Curves for Hitachi Units 17-27

4.2.1.2 Loading Order

For TEAM to load units for each sub-period, it needs to know the desired loading order. It is recognized that loading order and the number of hours each unit is loaded can vary by time of year. To determine the loading order, the Economic Analysis Team reviewed the historical data (Calendar Years 2000, 2001, and 2002) showing the monthly hours each unit was loaded. CY 2001 generation for Chief Joseph was well below normal (approximately 70% of average) so it was not used. CY 2002 generation was approximately 3% above average, but there were concerns about the relatively large variance of hours between units within the same family and several units that were out for extended periods that year. CY 2000 generation was approximately 8% above average, but the hours appeared well distributed between units and maintenance that year was considered more representative of normal. It was decided to use a loading order based on the monthly hours for CY 2000. It is also recognized that the FCRPS is moving towards using Near Real Time Optimization and the desire was to use a loading order that would be representative of likely future operations. A loading order was developed by ranking the units by their total monthly hours within existing families. Units 1-16 which are being evaluated for turbine runner replacements are considered the first family, and units 17-27 are considered the second family. A typical loading order was developed for each month where the unit with the most hours in the first family is considered the

first unit loaded and the unit with the most hours in the second family is considered the second unit loaded. Units alternate between families based on their relative rank in terms of hours, with the units with the least hours in either family being the last in that family. After all units have been accounted for in the second family (22 units total in the loading order), the order for the last five units is based on the hours in the month for the given units remaining in the first family.

After monthly loading sequences were developed, each week was assigned one of the monthly orders. Week 1 (which starts August 1st) was assigned the August loading order and each week was assigned the monthly loading order for the month that week fell within. For weeks that cross months, the month which contained more days of the week was used. For each of the alternatives, as a turbine runner was replaced, it was moved to the front of the loading order for the first family. It is important to keep in mind that benefits in terms of increased generation are determined by taking the difference between an alternative with a modified loading order and the base case with the initial loading order. By staggering the loading order between the units undergoing runner replacement and units not undergoing runner replacement, it is believed that a reasonable representation of benefits will be produced.

The 12 loading orders used are entered into TEAM on worksheet "Unit Operations." TEAM allows input of up to 14 different loading orders. The loading order assigned to each week is also entered on worksheet "Unit Operations." The loading order used in the base case is shown in Table 4-1.

Table 4-1 Assumed Base Case Loading Order

Month	Weeks	Assumed Unit Loading Order
August	1 - 4	16, 27, 7, 21, 11, 18, 6, 23, 10, 19, 8, 26, 9, 25, 15, 20, 14, 24, 5, 22, 1, 17, 4, 3, 12, 2, 13
September	5 - 9	16, 18, 15, 23, 14, 19, 9, 22, 11, 17, 10, 27, 2, 26, 1, 20, 3, 24, 4, 25, 5, 21, 8, 7, 12, 13, 6
October	10 - 13	4, 21, 8, 27, 2, 22, 3, 24, 7, 25, 10, 26, 1, 23, 6, 18, 5, 20, 15, 17, 11, 19, 9, 16, 12, 14, 13
November	14 - 17	5, 18, 10, 24, 1, 20, 16, 22, 3, 21, 9, 27, 2, 19, 7, 17, 8, 23, 4, 26, 11, 25, 6, 15, 12, 13, 14
December	18 - 22	10, 18, 3, 17, 6, 22, 7, 20, 5, 24, 2, 19, 16, 25, 1, 21, 4, 23, 15, 27, 8, 26, 9, 11, 12, 13, 14
January	23 - 26	1, 17, 14, 19, 5, 27, 3, 24, 9, 26, 2, 18, 15, 25, 7, 20, 8, 21, 6, 23, 10, 22, 16, 4, 11, 13, 12
February	27 - 30	8, 20, 9, 17, 4, 27, 2, 19, 16, 18, 5, 21, 1, 23, 3, 24, 7, 22, 11, 26, 6, 25, 15, 14, 12, 13, 10
March	31 - 35	14, 19, 2, 17, 1, 18, 6, 20, 5, 22, 4, 23, 16, 25, 3, 26, 9, 21, 11, 27, 8, 24, 7, 12, 10, 13, 15
April	36 - 39	2, 17, 5, 18, 14, 21, 8, 19, 3, 20, 4, 23, 11, 25, 6, 27, 10, 24, 7, 22, 1, 26, 9, 12, 13, 16, 15
May	40 - 43	14, 23, 8, 19, 6, 17, 1, 20, 12, 21, 3, 18, 10, 25, 2, 27, 4, 22, 5, 24, 7, 26, 9, 15, 11, 13, 16
June	44 - 48	10, 18, 8, 17, 6, 26, 4, 22, 2, 25, 16, 23, 3, 20, 1, 21, 14, 19, 9, 27, 7, 24, 15, 5, 11, 13, 12
July	49 - 52	2, 27, 6, 20, 4, 18, 8, 19, 16, 17, 10, 24, 1, 22, 15, 26, 9, 21, 14, 25, 7, 23, 3, 5, 11, 12, 13

4.2.1.3 Maintenance

TEAM allows up to a 5-year maintenance/unit outage cycle to be entered on a week-by-week basis specifying which units are unavailable for that week (from one to the entire plant if desired). For studies whose period of record exceeds the number of years in the cycle (50 were used in this study), TEAM repeats the cycle. In this study, a 4-year cycle was included, so for the first 4 years the cycle was used exactly as entered. In the fifth year of the study, the TEAM began the cycle again using year one in the cycle to represent year five in the study and so on. This data is entered into TEAM on worksheet "Unit Operations."

For the Chief Joseph study, the assumed maintenance cycle was based on the 5-year maintenance plan developed by the Project Office. Since benefits are being calculated based on the difference between two TEAM runs (Alternative minus Base Case), it was decided to only include maintenance that would change because of the turbine runner replacements. The 5-year plan includes major maintenance that generally occurs every 4 years, which is referred to as a "Quad." For units 1-16, the Quads are on a 4-year schedule so that the fifth year is a repeat of the first year. The Quad maintenance for each of these units is an 8-week outage. Units 17-27 are actually on a 5-year cycle for their Quads and the Quad for each of these units is four weeks. TEAM had to use a 4-year cycle rather than a 5-year cycle since the cycle begins repeating after 4 years for units 1-16. If a 5-year cycle had been used, based on TEAM's logic and 5-year maximum, units that were out in year five would have again been out in year six when the cycle began repeating itself. Using a 4-year cycle means that several units in the 17-27 family are not shown in the maintenance cycle at all. However, since the cycle repeats, the same number of units from this family is still out in the fifth year. Since all of units 17-27 are represented by the same performance curves, a representative number of these units are shown as unavailable, thus the results will not be significantly affected. In addition, the performance for these units does not change between the base case and the alternatives. In addition to the Quad maintenance, all units have a one week outage for annual maintenance shown in the 5-year plan. Since this maintenance does not change because of the study, it was not included in TEAM. Transformer maintenance was also not included in this study.

One of the key assumptions in this evaluation is that as a turbine runner is replaced, the Quad maintenance will be reduced from eight weeks to four weeks (same as units 17-27). This was done in TEAM by eliminating the final four weeks of each original Quad outage period as the turbine was replaced. The weekly outage assumptions used in the Base Case are shown in Table 4-2. Again, week one begins on August 1.

Table 4-2 Assumed Base Case Maintenance Schedule

Weeks	Assumed Unit Number Out			
	Maintenance Year Cycle			
	1	2	3	4
1	16			24
2 - 4	16	1		24
5 - 8	16	1		
9		1		
10-11	11			
12-13	11	5	6	
14-17	11	5	6	12
18-19	21	5	6	12
20 - 21	21			
23	15			
24 - 30	15	14	7	9
31		14	7	9
32 - 35	17	20	23	22
36-39	18	2	4	8
40-43	13	2	4	8
44	13			
45-47	13	19	3	10
48		19	3	10
49-52			3	10

4.2.1.4 Water Operations/Hydrology

TEAM requires water operation data for each week for every year evaluated. This is derived from long term flow data output from models such as HYSSR or HYDROSIM. TEAM can use up to 60 years of data. HYSSR and HYDROSIM provide operation data for 14 periods a year (12 months with April and August each split into two periods). One of the data items needed is the average flow for each period. TEAM derives the average weekly flow by using the monthly flows. If a week occurs entirely within one month, the average flow for that month is used for the week. If a week crosses two months, a weighted average based on the number of days of the week that occur in each of the two months is used to estimate the weekly flow.

In addition, the forebay elevation is needed for TEAM. This can either be entered for each period in the study or one constant number can be entered. In this evaluation a constant forebay elevation was assumed.

Although not used in this evaluation, TEAM allows flows for losses or non-power releases such as lockage, fish spills, and minimum period releases to be entered for each period. One set of values is used for all years if included.

A tailwater curve is included as part of this data. All of this data is entered on Worksheets "Water Monthly" and "Water Weekly."

For the Chief Joseph evaluation, HYDROSIM results for 50 years from Study 03sn67_04 (run for BPA's 2003 Safety-Net Cost Recovery Adjustment Clause rate case) were used as TEAM input. This run represents the current base operation for the system, including all operating constraints at the time the run was made.

4.2.1.5 Sub-Periods

After weekly flow data is developed if sub-periods are used, it needs to be converted to the sub-period flow. This is done using the Shaping Factors discussed in section 3.2.2, HOSS. These factors are entered into TEAM on Worksheet "Sub_Period_Monthly_Factors." Since these factors were developed for 14 periods similar to the original water operation data, they were converted to weekly factors in a manner similar to the water flows. These factors are calculated on Worksheet "Sub_Period_Weekly_Factors." These weekly factors are then used to calculate the average sub-period flows on Worksheet "Sub_Periods."

4.2.1.6 Other Inputs

Although not used in this evaluation, TEAM does allow additional constraints to be entered for powerplant operations. These include derating units, accounting for unit performance losses due to fish screens, and limiting unit operation to within 1% of the Best Efficiency Point. All of this data is entered on Worksheet "Unit_Operations."

Run execution is controlled on Worksheet "Control." The number of years included in the input data is set here, along with the number of periods (in this case weeks) in the year. The user can select the first and last year to run (anywhere from one to the total years available can be selected). The user can choose whether to run sub-periods or only use period average data. Run identifiers are also entered here. The user can select desired outputs here. The user can also choose to have Run Status messages written to this worksheet during TEAM execution. A prefix is entered for naming output worksheets. If the user decides to save the file, a unique file name based on run date and time and the run identifier is created. After the file is saved, the file name and time it is saved is written to this worksheet.

4.2.2 TEAM Outputs

Four types of output can be selected. Each type (except Debug) is written to its own Worksheet. Desired output and corresponding worksheet names are set in Worksheet "CONTROL."

Output Types:

Detailed Unit Output	Provides period-by-period detailed loading information. Only for monthly data of 10 years or less.
Quick Unit Output	Added to VB version as an alternative to the existing detailed unit output. Provides abbreviated period-by-period output. Much quicker than detailed unit output.
Table Output	User-friendly tabular output used for investment evaluations. Available for individual sub-periods and runs based on period average flows without sub-periods. A sub-period summary table is also produced.
Debug	These were the embedded write statements used for debugging included in the original HALLO. Writes to a text file.

4.3 TEAM Scenarios

4.3.1 Overview of Scenarios

The scope of the investigation was focused on replacing some number of the turbine runners for units 1-16 at Chief Joseph. The analyses were set up to evaluate the economic cost and benefits for each unit runner replacement on an incremental basis. A number of additional scenarios were evaluated to investigate certain aspects of the final recommended action, to calculate outage impacts associated with a replacement project, or to test how robust or sensitive were the economic results for turbine runner replacements. In all, 56 runs were identified and evaluated through TEAM.

The various runs are grouped into four categories (scenarios):

- Base case condition (1 run)
- Runner replacements ranging from 1 unit replaced up to 16 units replaced (16 runs)
- Outage runs used to evaluate the cost of future turbine runner replacements (9 runs)
- Sensitivity scenario (30 runs)

Table 4-3 summarizes the scenarios included in the first three categories, while Table 4-4 summarizes the scenarios included in the fourth category. The tables define each scenario in terms of TEAM run ID, number of runners replaced, units out for runner replacement, units with new runners, number of units available, and a comment describing the scenario category.

4.3.1.1 Base Case Condition

Using the performance characteristics of the existing turbine runners simulated the base case condition. Each runner is classified into one of three families of turbines at the project. All runners within a single family are assumed to have identical performance. The primary assumption needed for the simulation is the unit loading order as discussed in section 4.2.1.2. The key results for the base case are average energy generation by period, for each week for all units, or for the plant as a whole. An annual average total production is calculated as the sum of the period generations. All three families of units are included in the total value.

4.3.1.2 Incremental Runner Replacement

The runner replacement analysis began by determining the energy generation benefits associated with each runner replacement on an incremental basis. In other words, a run was made that assumed one new runner was installed and operating. Average generation in each period for each week was determined. This generation was compared to the generation in the base case condition. The difference in energy was calculated and ultimately valued. This difference represented the benefit achieved for the replacement of the first runner. Additional runs were made by incrementing the total number of runners replaced one at a time. The runners of the Newport News family, representing units 5-14, were replaced first (a total of 10 runners). The S. Morgan Smith family of runners, representing units 1-4, 15 and 16, was replaced second (a total of six runners). Run CHJ_10 provides the benefits for replacement of the entire first family, and run CHJ_16 provides the benefits for runner replacement of both families.

As was noted under the base case condition, a key assumption in this incremental analysis is the order for runner replacements. Run CHJ_16 in Table 4-3, column labeled Units with New Runners, shows the order by unit number for runner replacements. As each new runner is replaced, it is moved up in the loading order for the subject run and remains in that order for operation in all subsequent runs. The reason for the change in loading order is that the new runner has greater efficiency than the remaining unchanged runners within the families. Replacement of the Hitachi runners (units 17-27) was not considered or simulated. Their loading order remains unchanged in all runs.

4.3.1.3 Outage Scenario

Table 4-3 also includes several simulations with the suffix "Out," "OutA," or "OutB" in the run ID. These simulations assume that one or two units are unavailable for operation for a period of 29 weeks during the year. They represent the units that are having new runners installed. By comparing these runs to the base case condition or to an incremental run having the same number of old runners in service, the costs of the outage

for runner replacement are determined. These costs were important for estimating the overall economics of the investment, particularly during the construction and runner replacement phase. A total of nine simulations were run. The first and last run had one unit out of service for runner replacement; the remaining seven runs had two units out of service.

Table 4-5 summarizes the start and end dates that were assumed in TEAM for each 29-week runner replacement outage. Each start and end date is shown in terms of the TEAM year and week, where Year 1 is the first year of the runner replacement schedule and Week 1 begins on August 1. The date shown within parenthesis represents the calendar month and day when the 29-week outage starts and ends.

4.3.1.4 Sensitivity Scenario

A series of sensitivity runs were completed to estimate the robustness of the economics of runner replacement, to provide the potential contractors with information, and to calculate damages. They are listed in Table 4-4. Most of the runs involved 10 or 16 unit runner replacements with changes in runner performance up or down, or limits on generator capacity. They are based on one of the incremental runner replacement or outage runs with some alteration to the assumptions. These results were incorporated into the economic analyses as described in section 7. The EBG, EFG, and PFG abbreviations included in the comment column on Table 4-4 refer to TEAM unit performance polynomials that represent unit overall efficiency at best gate (EBG), unit overall efficiency at full gate (EFG) and unit power output at full gate (PFG).
A description of the unit performance polynomials that serve as input to TEAM is given in section 4.2.1.1

Table 4-3 TEAM Base Case, Incremental Runner and Outage Runs

Team Run ID	Number of New Runners	Units Out For Runner Replacement	Units With New Runners	Number of Units Available	Comment
1 CHJ	0	None	None	27	Base Case - existing units only
2 CHJ_01	1	None	11	27	Incremental benefits from first unit with new runner
3 CHJ_01_Out	0	11	None	26	For economic analysis outage cost calculation - Unit 11 out 29 weeks (see Table 4-5 for schedule)
4 CHJ_02	2	None	11,9	27	Incremental benefits from two units with new runner
5 CHJ_03	3	None	11,9,10	27	Incremental benefits from three units with new runner
6 CHJ_04	4	None	11,9,10,12	27	Incremental benefits from four units with new runner
7 CHJ_05	5	None	11,9,10,12,14	27	Incremental benefits from five units with new runner
8 CHJ_05_OutA	1	9,10	11	25	For economic analysis outage cost calculation - Units 9 & 10 out 29 weeks (see Table 4-5 for schedule)
9 CHJ_05_OutB	3	12,14	11,9,10	25	For economic analysis outage cost calculation - Units 12 & 14 out 29 weeks (see Table 4-5 for schedule)
10 CHJ_06	6	None	11,9,10,12,14,13	27	Incremental benefits from six units with new runner
11 CHJ_07	7	None	11,9,10,12,14,13,8	27	Incremental benefits from seven units with new runner
12 CHJ_08	8	None	11,9,10,12,14,13,8,6	27	Incremental benefits from eight units with new runner
13 CHJ_09	9	None	11,9,10,12,14,13,8,6,5	27	Incremental benefits from nine units with new runner
14 CHJ_09_OutA	5	13,8	11,9,10,12,14	25	For economic analysis outage cost calculation - Units 13 & 8 out 29 weeks (see Table 4-5 for schedule)
15 CHJ_09_OutB	7	6,5	11,9,10,12,14,13,8	25	For economic analysis outage cost calculation - Units 6 & 5 out 29 weeks (see Table 4-5 for schedule)
16 CHJ_10	10	None	11,9,10,12,14,13,8,6,5,7	27	Incremental benefits from ten units with new runner
17 CHJ_11	11	None	11,9,10,12,14,13,8,6,5,7,15	27	Incremental benefits from eleven units with new runner
18 CHJ_12	12	None	11,9,10,12,14,13,8,6,5,7,15,16	27	Incremental benefits from twelve units with new runner
19 CHJ_13	13	None	11,9,10,12,14,13,8,6,5,7,15,16,4	27	Incremental benefits from thirteen units with new runner
20 CHJ_13_OutA	9	7,15	11,9,10,12,14,13,8,6,5	25	For economic analysis outage cost calculation - Units 7 & 15 out 29 weeks (see Table 4-5 for schedule)
21 CHJ_13_OutB	11	16,4	11,9,10,12,14,13,8,6,5,7,15	25	For economic analysis outage cost calculation - Units 16 & 4 out 29 weeks (see Table 4-5 for schedule)
22 CHJ_14	14	None	11,9,10,12,14,13,8,6,5,7,15,16,4,2	27	Incremental benefits from fourteen units with new runner
23 CHJ_15	15	None	11,9,10,12,14,13,8,6,5,7,15,16,4,2,3	27	Incremental benefits from fifteen units with new runner
24 CHJ_16	16	None	11,9,10,12,14,13,8,6,5,7,15,16,4,2,3,1	27	Incremental benefits from sixteen units with new runner
25 CHJ_16_OutA	13	2,3	11,9,10,12,14,13,8,6,5,7,15,16,4	25	For economic analysis outage cost calculation - Units 2 & 3 out 29 weeks (see Table 4-5 for schedule)
26 CHJ_16_OutB	15	1	11,9,10,12,14,13,8,6,5,7,15,16,4,2,3	26	For economic analysis outage cost calculation - Unit 1 out 29 weeks (see Table 4-5 for schedule)

Table 4-4 Sensitivity Runs

Team Run ID	Number of New Runners	Units Out For Runner Replacement	Units With New Runners	Number of Units Available	Comment
27 CHJ_16_160	16	None	11,9,10,12,14,13,8,6,5,7,15,16,4,2,3,1	27	Run 24 with performance equations of Units 1-16 based on a rated net head of 160 feet
28 CHJ_16_AltLO	16	None	11,9,10,12,14,13,8,6,5,7,15,16,4,2,3,1	27	Run 24 with alternate loading order: load Units 17-27 first, then load Units 1-16 in the order runners are replaced
29 CHJ_10_1P	10	None	11,9,10,12,14,13,8,6,5,7	27	Run 16 with 0.1% more efficiency on Units 5-14 (add 0.1 to A0 term of EBG & EFG)
30 CHJ_10_2P	10	None	11,9,10,12,14,13,8,6,5,7	27	Run 16 with 0.2% more efficiency on Units 5-14 (add 0.2 to A0 term of EBG & EFG)
31 CHJ_10_3P	10	None	11,9,10,12,14,13,8,6,5,7	27	Run 16 with 0.3% more efficiency on Units 5-14 (add 0.3 to A0 term of EBG & EFG)
32 CHJ_10_4P	10	None	11,9,10,12,14,13,8,6,5,7	27	Run 16 with 0.4% more efficiency on Units 5-14 (add 0.4 to A0 term of EBG & EFG)
33 CHJ_10_5P	10	None	11,9,10,12,14,13,8,6,5,7	27	Run 16 with 0.5% more efficiency on Units 5-14 (add 0.5 to A0 term of EBG & EFG)
34 CHJ_16_1P	16	None	11,9,10,12,14,13,8,6,5,7,15,16,4,2,3,1	27	Run 24 with 0.1% more efficiency on Units 1-4,15,16 (add 0.1 to A0 term of EBG & EFG)
35 CHJ_16_2P	16	None	11,9,10,12,14,13,8,6,5,7,15,16,4,2,3,1	27	Run 24 with 0.2% more efficiency on Units 1-4,15,16 (add 0.2 to A0 term of EBG & EFG)
36 CHJ_16_3P	16	None	11,9,10,12,14,13,8,6,5,7,15,16,4,2,3,1	27	Run 24 with 0.3% more efficiency on Units 1-4,15,16 (add 0.3 to A0 term of EBG & EFG)
37 CHJ_16_4P	16	None	11,9,10,12,14,13,8,6,5,7,15,16,4,2,3,1	27	Run 24 with 0.4% more efficiency on Units 1-4,15,16 (add 0.4 to A0 term of EBG & EFG)
38 CHJ_16_5P	16	None	11,9,10,12,14,13,8,6,5,7,15,16,4,2,3,1	27	Run 24 with 0.5% more efficiency on Units 1-4,15,16 (add 0.5 to A0 term of EBG & EFG)
39 CHJ_16_5yr	16	None	11,9,10,12,14,13,8,6,5,7,15,16,4,2,3,1	27	Run 24 with a 5-year rotation for future maintenance of Units 1-27
40 CHJ_Base_77	0	None	None	27	Run 1 with a 77 MW generator limit on all Units 1-16
41 CHJ_10_77	10	None	11,9,10,12,14,13,8,6,5,7	27	Run 16 with a 77 MW generator limit on all Units 1-16
42 CHJ_16_77	16	None	11,9,10,12,14,13,8,6,5,7,15,16,4,2,3,1	27	Run 24 with a 77 MW generator limit on all Units 1-16
43 CHJ_10_Neg1P	10	None	11,9,10,12,14,13,8,6,5,7	27	Run 16 with 0.1% less efficiency on Units 5-14 (subtract 0.1 from A0 term of EBG & EFG)
44 CHJ_16_Neg1P	16	None	11,9,10,12,14,13,8,6,5,7,15,16,4,2,3,1	27	Run 24 with 0.1% less efficiency on Units 1-4,15,16 (subtract 0.1 from A0 term of EBG & EFG)
45 CHJ_10_Minus1000HP	10	None	11,9,10,12,14,13,8,6,5,7	27	Run 16 with 1000 less max. HP on Units 5-14 (subtract 1000 HP equiv. in MW from A0 term of PFG)
46 CHJ_16_Minus1000HP	16	None	11,9,10,12,14,13,8,6,5,7,15,16,4,2,3,1	27	Run 24 with 1000 less max. HP on Units 1-4,15,16 (subtract 1000 HP equiv. in MW from A0 term of PFG)
47 CHJ_01_5P	1	None	11	27	Run 2 with 0.5% more efficiency on Unit 11 (add 0.5 to A0 term of EBG & EFG)
48 CHJ_16_5PAll	16	None	11,9,10,12,14,13,8,6,5,7,15,16,4,2,3,1	27	Run 24 with 0.5% more efficiency on Units 1-16 (add 0.5 to A0 term of EBG & EFG)
49 CHJ_05_OutA_5P	1	9,10	11	25	Run 8 with 0.5% more efficiency on Unit 11 (add 0.5 to A0 term of EBG & EFG)
50 CHJ_05_OutB_5P	3	12,14	11,9,10	25	Run 9 with 0.5% more efficiency on Units 9-11 (add 0.5 to A0 term of EBG & EFG)
51 CHJ_09_OutA_5P	5	13,8	11,9,10,12,14	25	Run 14 with 0.5% more efficiency on Units 9-12 and 14 (add 0.5 to A0 term of EBG & EFG)
52 CHJ_09_OutB_5P	7	6,5	11,9,10,12,14,13,8	25	Run 15 with 0.5% more efficiency on Units 8-14 (add 0.5 to A0 term of EBG & EFG)
53 CHJ_13_OutA_5P	9	7,15	11,9,10,12,14,13,8,6,5	25	Run 20 with 0.5% more efficiency on Units 5-6 and 8-14 (add 0.5 to A0 term of EBG & EFG)
54 CHJ_13_OutB_5P	11	16,4	11,9,10,12,14,13,8,6,5,7,15	25	Run 21 with 0.5% more efficiency on Units 5-15 (add 0.5 to A0 term of EBG & EFG)
55 CHJ_16_OutA_5P	13	2,3	11,9,10,12,14,13,8,6,5,7,15,16,4	25	Run 25 with 0.5% more efficiency on Units 4-16 (add 0.5 to A0 term of EBG & EFG)
56 CHJ_16_OutB_5P	15	1	11,9,10,12,14,13,8,6,5,7,15,16,4,2,3	26	Run 26 with 0.5% more efficiency on Units 2-16 (add 0.5 to A0 term of EBG & EFG)

Table 4-5 Start and End Dates for Runner Replacement Outages

Unit Having Runner Replaced	Runner Replacement Start Date	Runner Replacement End Date
11	TEAM Yr 1, Wk 36 (Apr 03)	TEAM Yr 2, Wk 12 (Oct 23)
9	TEAM Yr 2, Wk 20 (Dec 12)	TEAM Yr 2, Wk 48 (Jul 02)
10	TEAM Yr 2, Wk 22 (Dec 26)	TEAM Yr 2, Wk 50 (Jul 16)
12	TEAM Yr 2, Wk 49 (Jul 03)	TEAM Yr 3, Wk 25 (Jan 22)
14	TEAM Yr 2, Wk 51 (Jul 17)	TEAM Yr 3, Wk 27 (Feb 05)
13	TEAM Yr 3, Wk 26 (Jan 23)	TEAM Yr 4, Wk 02 (Aug 14)
8	TEAM Yr 3, Wk 28 (Feb 06)	TEAM Yr 4, Wk 04 (Aug 28)
6	TEAM Yr 4, Wk 03 (Aug 15)	TEAM Yr 4, Wk 31 (Mar 05)
5	TEAM Yr 4, Wk 05 (Aug 29)	TEAM Yr 4, Wk 33 (Mar 19)
7	TEAM Yr 4, Wk 32 (Mar 06)	TEAM Yr 5, Wk 08 (Sep 25)
15	TEAM Yr 4, Wk 34 (Mar 20)	TEAM Yr 5, Wk 10 (Oct 09)
16	TEAM Yr 5, Wk 09 (Sep 26)	TEAM Yr 5, Wk 37 (Apr 16)
4	TEAM Yr 5, Wk 11 (Oct 10)	TEAM Yr 5, Wk 39 (Apr 30)
2	TEAM Yr 5, Wk 38 (Apr 17)	TEAM Yr 6, Wk 14 (Nov 06)
3	TEAM Yr 5, Wk 40 (May 01)	TEAM Yr 6, Wk 16 (Nov 20)
1	TEAM Yr 6, Wk 15 (Nov 07)	TEAM Yr 6, Wk 43 (May 28)

5.0 Valuation of Increased Energy Output

5.1 Overview

As part of the ongoing investigation of turbine runner replacements at Chief Joseph Project, BPA has developed and provided to the COE projected hourly market-clearing prices based on the 50 years of hydrologic data used in estimating energy production. These projections were developed using an electric energy market model called AURORA. AURORA is owned and licensed by EPIS, Incorporated.

5.2 AURORA Production Cost Model

The hourly market-clearing price is based upon a fixed set of resources dispatched in least-cost order to meet demand. The hourly price is set equal to the variable cost of the marginal resource needed to meet the last unit of demand. A long-term resource optimization feature within the AURORA model allows generating resources to be added or retired based on economic profitability. Market-clearing price and the resource portfolio are interdependent. Market-clearing price affects the revenues any particular resource can earn and consequently will affect which resources are added or retired. Iterative solutions of resource portfolios and market-clearing prices are completed in AURORA until the difference between the last two iterations is minimal. AURORA sets the market-clearing price using assumptions of demand levels (load) and supply costs. The demand forecast implicitly includes the effect of price elasticity over time. The supply side is defined by the cost and operating characteristics of individual electric generating plants, including resource capacity, heat rate, and fuel price. AURORA incorporates the effect that transmission capacity and prices have on the system's ability to move generation output between areas. AURORA recognizes 13 areas within the WECC, largely defined by major transmission interconnections. For example, California is split into two market areas, north and south; Oregon, Washington, and Northern Idaho are combined while Southern Idaho is a separate market area; and British Columbia and Alberta (Canada) are combined into a single market area.

Assumptions in AURORA for determining power values:

- Load year Oct. 2009 - Sept. 2010 was modeled using AURORA.
- 50 water years of regional monthly generation obtained from BPA's HYDROSIM model served as input to AURORA.
- For each of the 50 water years, monthly generation was simulated for the modeled load year.
- An hourly marginal cost for each hour of the period Oct. 2009 to Sept. 2010 was determined for each water year's generation.
- BPA provided 8,760 hourly marginal costs values for each of the 50 water years (leap years are not considered).

- These values represent the Mid-Columbia trading prices.

To describe AURORA's methodology, it is helpful to distinguish between two main aspects of modeling the electric energy market: the short-term determination of the hourly market-clearing price and the long-term optimization of the resource portfolio.

5.2.1 Hourly Price Determination

As noted earlier, the hourly market-clearing price is based upon a fixed set of resources dispatched in least-cost order to meet demand. The hourly price is set equal to the variable cost of the marginal resource.

AURORA places two restrictions on the hourly operation of generating plants. First, AURORA simulates the "must run" status of certain units. Second, AURORA recognizes that costs associated with ramping generation levels up and down will make the economic dispatch of plants on an hourly basis impractical. To account for this, AURORA commits generating plants to operate at weekly intervals. AURORA uses a weekly price forecast to determine plant profitability and to model the commitment decision.

5.2.2 Long -Term Resource Optimization

The long-term resource optimization feature within AURORA allows generating resources to be added or retired based on economic profitability. Economic profitability is measured as the net present value (NPV) of revenue minus the NPV of costs. A potential new resource that is economically profitable will be added to the resource database. An existing resource that is not economically profitable will be retired from the resource database.

In reality, the market-clearing price (hence the profitability of a resource) and the resource portfolio are interdependent. The market-clearing price will affect the revenues any particular resource can earn, and consequently, it will affect which resources are added and retired. In the same way, changes in the resource portfolio will change the supply cost structure, which will affect the market-clearing price. AURORA uses an iterative process to address this interdependency.

AURORA's iterative process uses a preliminary price forecast to evaluate existing and potential new resources in terms of their economic profitability. If an existing resource is not profitable, it becomes a candidate for retirement. Alternatively, if a potential new resource is economically profitable, it is a candidate to be added to the resource portfolio. In the first step of the iterative process, a small set of new resources is drawn from those with the greatest profitability and added to the resource base. Similarly, a small set of the most unprofitable existing resources is retired. This modified resource portfolio is used in the next step in the iterative process to derive a revised market-clearing price forecast. The modified price will then drive a new iteration of resource changes. AURORA will

continue the iterative solution of the resources portfolio and the market-clearing price until the difference in price between the last two iterations reaches a minimum and the iterations converge on a stable solution.

5.3 Energy Values Used in Evaluation

The hourly Aurora energy values cannot be directly used in the evaluation since TEAM is calculating average weekly generation. To derive average weekly prices, the hourly AURORA prices were grouped into three weekly sub-periods: Super Peak (SP), Heavy Load Hours (HLH), and Light Load Hours (LLH) for each of the weeks in the 50-year period of record. The following assumptions were used:

- SP - Super Peak will be defined as the highest price 6 hours per day during the traditional HLH period (6 AM to 10 PM or 0600 to 2200) for the days Monday through Friday for a total of 30 hours per average week.

- HLH - Heavy Load Hours are usually the 16 hours per day for the period 6 AM to 10 PM (0600 to 2200) for Monday through Saturday for a total of 96 Hours per week. Since this includes Super Peak hours, which are a subset of HLH, the HLH in this file is limited to 66 hours per week. This is based on 96 hours – 30 Super-Peak Hours (highest 6 hours for each day Monday through Friday).

- LLH - (Light Load Hours) are 8 hours Monday through Saturday and all day Sunday for a total of 72 hours per week. Although certain holidays are considered LLH for the entire day, they are not included in the breakdown used here.

- Holidays and Daylight Savings not accounted for.

- Days used to break down sub-periods are based on August 2009 through July 2010 for all Water Years.

- Each week has seven days except for Week 52, which has eight days. Based on the assumed year for prices, this extra day is a Saturday, so the last week has 192 hours, but only 30 Super Peak hours.

Hourly prices were converted to weekly averages for each water year. The result was a 50 Water Year by 52 Week table of power values for each sub-period.

The average weekly prices are shown in Figure 5-1.

[redacted])

5.4 Determining Energy Benefits for Each Alternative

To determine the power benefits associated with each alternative, an Excel spreadsheet called "COMPARE" was developed that utilized the output of TEAM and the weekly energy values described in section 5.3. For each TEAM run, a worksheet is created that provides results on a weekly basis on the amount of generation for each of the three sub-periods: Super-Peak, Heavy Load Hours, and Light Load Hours over the entire hydrologic period used. Copies of this sheet were moved into COMPARE for all alternatives including the Base Case. Weekly power values for all years in the hydrologic period were also loaded into COMPARE. After all TEAM runs were completed and the results copied into COMPARE, any combination of two TEAM runs could be selected to determine the power benefits for a desired alternative. For example, the TEAM run showing one turbine runner replaced could be compared to the Base Case alternative to determine the benefits for replacement of the first turbine runner. Likewise, a TEAM run showing two turbine runners replaced could be compared to the TEAM run showing one turbine runner replaced to show the incremental benefits going from one turbine runner replacement to two turbine runner replacements.

Benefits in COMPARE are calculated on a weekly time step for each sub-period and for each year in the hydrologic period. They were then averaged over the entire hydrologic period and the three sub-periods were summed to get the total average benefit for each week. These weekly average benefits can then be summed to get an average annual benefit, or selected weeks within the year can be summed to get benefits for a specific period within the year.

6.0 Energy Analysis

6.1 *Overview*

As explained in section 4, the Turbine Energy Analysis Model (TEAM) was used to develop estimates of Chief Joseph energy generation for a number of study scenarios, which are defined in Tables 4-3 and 4-4. For each scenario, TEAM employed the procedure summarized in section 4.2 to allocate the available flow on a week-by-week, sub-period by sub-period, and unit-by-unit basis for each year in the study 50-year period of record, taking into account the unit loading orders and unit maintenance schedule that served as input to the model. Once TEAM had allocated the available flow, the model used the appropriate unit performance data to determine the generation contributed by the project under each scenario. The generation results obtained from this process were used in the Chief Joseph economic analysis described in section 7.

Figure 6-1 displays the Chief Joseph weekly average base case generation estimates (expressed in average MW (aMW)) developed by TEAM, where week 1 begins on August 1. Weekly generation estimates are displayed for the project total generation as well as for the three weekly sub-periods: Super Peak Hour (SPH), Heavy Load Hour (HLH) and Light Load Hour (LLH). Figure 6-1 shows that the weekly average generation is the highest during Weeks 23 through 26 (January) and during Weeks 39 through 2 (late-April through mid-August).

[redacted]

Table 6-1 summarizes, for each scenario, the Chief Joseph average annual generation estimate (expressed in GWh and aMW) developed by TEAM, along with the gain or loss in project annual generation relative to the base case.

Table 6-1 is separated into two sections. The first section, consisting of Scenarios 1-26, represents three categories of TEAM runs:

- Base case run, in which units 1-16 are in their existing condition (Run 1).

- Runner replacement runs, which are used to measure the generation gains obtained by incrementally replacing from 1 up through 16 turbine runners on units 1-16 (Runs 2, 4-7, 10-13, 16-19, and 22-24).

- Unit outage runs, which are used to measure the generation impacts of taking one or more units out of service for runner replacement (Runs 3, 8-9, 14-15, 20-21, and 25-26).

The second section of Table 6-1, consisting of scenarios 27-56, represents TEAM runs that were used to:

- Determine how sensitive the economics of turbine runner replacements are with respect to changes in study assumptions, such as unit loading order, unit maintenance schedule, and replacement runner performance.

- Establish charges to assess the turbine contractor in the event the replacement runners fail to meet contract guarantees.

Not all of the TEAM run results for scenarios 27-56 were used. The Chief Joseph economic analysis involving the failure to meet contract guarantees is described in section 7.7.

Table 6-1 Average Annual Energy Generation by Scenario

Team Run ID	Number of New Runners	Units Out For Runner Replacement	Average Annual Energy Generation		Gain / Loss in Annual Energy From the Base Case (Run 1)	
			GWh	aMW	GWh	aMW
1 CHJ	0	None	12,315	1,406	------	------
2 CHJ_01	1	None	12,351	1,410	36	4
3 CHJ_01_Out	0	11	12,286	1,403	-29	-3
4 CHJ_02	2	None	12,388	1,414	73	8
5 CHJ_03	3	None	12,425	1,418	110	13
6 CHJ_04	4	None	12,460	1,422	145	17
7 CHJ_05	5	None	12,491	1,426	176	20
8 CHJ_05_OutA	1	9,10	12,285	1,402	-30	-3
9 CHJ_05_OutB	3	12,14	12,411	1,417	96	11
10 CHJ_06	6	None	12,520	1,429	205	23
11 CHJ_07	7	None	12,548	1,432	233	27
12 CHJ_08	8	None	12,571	1,435	256	29
13 CHJ_09	9	None	12,590	1,437	275	31
14 CHJ_09_OutA	5	13,8	12,431	1,419	116	13
15 CHJ_09_OutB	7	6,5	12,536	1,431	221	25
16 CHJ_10	10	None	12,606	1,439	291	33
17 CHJ_11	11	None	12,617	1,440	302	34
18 CHJ_12	12	None	12,626	1,441	311	35
19 CHJ_13	13	None	12,636	1,443	321	37
20 CHJ_13_OutA	9	7,15	12,523	1,430	208	24
21 CHJ_13_OutB	11	16,4	12,604	1,439	289	33
22 CHJ_14	14	None	12,646	1,444	331	38
23 CHJ_15	15	None	12,654	1,444	339	39
24 CHJ_16	16	None	12,659	1,445	344	39
25 CHJ_16_OutA	13	2,3	12,579	1,436	264	30
26 CHJ_16_OutB	15	1	12,637	1,443	322	37

Sensitivity Runs

27 CHJ_16_160	16	None	------	------	------	------
28 CHJ_16_AltLO	16	None	12,688	1,448	373	43
29 CHJ_10_1P	10	None	12,611	1,440	296	34
30 CHJ_10_2P	10	None	12,616	1,440	302	34
31 CHJ_10_3P	10	None	12,622	1,441	307	35
32 CHJ_10_4P	10	None	12,627	1,441	312	36
33 CHJ_10_5P	10	None	12,632	1,442	318	36
34 CHJ_16_1P	16	None	12,660	1,445	345	39
35 CHJ_16_2P	16	None	12,661	1,445	346	39
36 CHJ_16_3P	16	None	12,662	1,445	347	40
37 CHJ_16_4P	16	None	12,662	1,445	347	40
38 CHJ_16_5P	16	None	12,663	1,446	348	40
39 CHJ_16_5yr	16	None	12,675	1,447	360	41
40 CHJ_Base_77	0	None	------	------	------	------
41 CHJ_10_77	10	None	------	------	------	------
42 CHJ_16_77	16	None	------	------	------	------
43 CHJ_10_Neg1P	10	None	12,600	1,438	286	33
44 CHJ_16_Neg1P	16	None	12,658	1,445	344	39
45 CHJ_10_Minus1000HP	10	None	12,603	1,439	288	33
46 CHJ_16_Minus1000HP	16	None	12,658	1,445	343	39
47 CHJ_01_5P	1	None	12,355	1,410	40	5
48 CHJ_16_5PAll	16	None	12,690	1,449	375	43
49 CHJ_05_OutA_5P	1	9,10	12,288	1,403	-27	-3
50 CHJ_05_OutB_5P	3	12,14	12,421	1,418	106	12
51 CHJ_09_OutA_5P	5	13,8	12,447	1,421	132	15
52 CHJ_09_OutB_5P	7	6,5	12,558	1,434	243	28
53 CHJ_13_OutA_5P	9	7,15	12,548	1,432	233	27
54 CHJ_13_OutB_5P	11	16,4	12,632	1,442	317	36
55 CHJ_16_OutA_5P	13	2,3	12,608	1,439	293	33
56 CHJ_16_OutB_5P	15	1	12,668	1,446	353	40

Note: TEAM results for Scenarios 27, 40-42 were not used in the Chief Joseph turbine runner replacement study.

6.2 Energy Gains Associated With Turbine Runner Replacement

The economic analysis performed for the Chief Joseph turbine runner replacement study evaluated the benefits and costs associated with replacing one or more turbine runners on units 1-16. This process was carried out on an incremental basis in order to determine the number of runner replacements that could be economically justified.

A major component in determining the incremental benefits of runner replacement involved estimating the incremental gain in project generation that could be achieved under runner replacement. The incremental gains in project generation are a result of increased efficiency and generating capability that is achieved when runners are replaced.

The incremental gain in project generation associated with turbine runner replacement on a particular unit from units 1-16 was obtained by determining the project generation after the runner is replaced, determining the project generation before the runner is replaced, and then computing the difference between the generation estimates.

Table 6-2 summarizes the incremental gain in annual generation (expressed in GWh and in aMW) that was obtained for each replaced runner. The fourth column in the table identifies the unit whose turbine runner was replaced, while the first column in the table identifies the TEAM runs whose generation results were used in determining the incremental gain in annual generation achieved by replacing the runner.

Table 6-2 New Runner Energy Gains

TEAM Run Numbers	Number of New Runners	Number of Units Out For Runner Replacement	Last Unit With New Runner	Incremental Gain in Annual Energy	
				GWh	aMW
1, 2	1	0	11	36.3	4.1
2, 4	2	0	9	36.3	4.1
4, 5	3	0	10	37.6	4.3
5, 6	4	0	12	34.4	3.9
6, 7	5	0	14	31.4	3.6
7, 10	6	0	13	29.5	3.4
10, 11	7	0	8	27.9	3.2
11, 12	8	0	6	22.7	2.6
12, 13	9	0	5	19.2	2.2
13, 16	10	0	7	15.5	1.8
16, 17	11	0	15	11.1	1.3
17, 18	12	0	16	8.9	1.0
18, 19	13	0	4	10.7	1.2
19, 22	14	0	2	9.5	1.1
22, 23	15	0	3	7.8	0.9
23, 24	16	0	1	5.5	0.6

Table 6-2 results indicate that the incremental gains in project annual generation tend to decrease as an increasing number of runners on units 1-16 are replaced. This is especially true when half or more of the runners are replaced. The main reasons for this behavior have to do with the availability of flow for generation and the assumptions regarding unit loading orders. In allocating flow on a week-by-week, sub-period by sub-period, and unit-by-unit basis over the 50-year period of record, TEAM determined that a majority of the time only a fraction of the 27 Chief Joseph units could be supported with the available flow.

Although runner replacement on a unit increases its efficiency and generating capability and although a unit with a new runner is placed at the beginning of the loading order, as additional runners are replaced there is an increasing likelihood that there will be insufficient flow in many weeks to support the generating capability of all the units that have new runners. This is especially true when half or more of the units have new runners, since one of the loading order assumptions of the Chief Joseph study was that units from units 1-16 and units from units 17-27 would be loaded on an alternating basis in the TEAM simulations.

6.3 Energy Losses Associated with Unit Outages for Turbine Runner Replacement

The economic analysis performed for the Chief Joseph turbine runner replacement study assumed that the amount of time required for runner replacement on units 1-16 could be as long as 6 years, depending on how many of the 16 turbine runners are replaced. During the replacement period, one or two units were assumed to be out of service at any given time for a total of 29 weeks. For the most part, after a unit had been returned to service, another unit was immediately taken out of service for runner replacement.

One of the costs estimated in the economic analysis was the power benefits forgone (i.e., power costs) associated with taking units out of service for runner replacement. To estimate these costs, it was necessary to estimate the loss in project generation that resulted when units were taken out of service. The loss in project generation associated with taking a particular unit from units 1-16 out of service for runner replacement was obtained by determining the project generation before the unit is taken out service, determining the project generation while the unit is out of service for runner replacement, and then computing the difference between the generation estimates.

Table 6-3 summarizes the loss in project generation (expressed in GWh and in aMW) that was obtained for each unit (or pair of units) taken out of service for runner replacement. The fourth column in the table identifies the unit(s) assumed to be out of service, while the first column in the table identifies the TEAM runs whose generation results were used in determining the loss in annual generation resulting from the unit outage.

Table 6-3 Unit Outage Energy Losses

TEAM Run Numbers	Number of New Runners	Number of Units Out For Runner Replacement	Units Out For Runner Replacement	Total Outage Loss in Annual Energy		Per Unit Outage Loss in Annual Energy	
				GWh	aMW	GWh	aMW
1, 3	0	1	11	-28.7	-3.3	-28.7	-3.3
2, 8	1	2	9, 10	-66.3	-7.6	-33.1	-3.8
5, 9	3	2	12, 14	-14.3	-1.6	-7.1	-0.8
7, 14	5	2	13, 8	-59.9	-6.8	-30.0	-3.4
11, 15	7	2	6, 5	-12.1	-1.4	-6.0	-0.7
13, 20	9	2	7, 15	-67.0	-7.6	-33.5	-3.8
17, 21	11	2	16, 4	-12.7	-1.4	-6.3	-0.7
19, 25	13	2	2, 3	-57.2	-6.5	-28.6	-3.3
23, 26	15	1	1	-16.6	-1.9	-16.6	-1.9

Table 6-3 results indicate that the loss in project generation due to unit outages can vary considerably. The main reason for this behavior has to do with the time of the year when a unit outage takes place, although the number of units that are out of service is also a factor. Figure 6-1 showed that the largest impact on project generation takes place during TEAM weeks 39 through 2, which corresponds to the period late-April through mid-August. Table 6-3 shows that the unit outages with the largest loss in project generation are [9, 10], [13, 8], [7, 15], and [2, 3]. According to Table 4-5 in section 4.3, the 29-week unit outage for each of these particular units includes most or all of weeks in the period late-April through mid-August.

6.4 Energy Gains and Losses Associated With the Sensitivity Analysis

As noted in section 6.1 and summarized in the lower half of Table 6-1, a number of TEAM runs were performed in order to determine how sensitive the economics of runner replacement is with respect to changes in TEAM input assumptions. Only sensitivity runs that showed significant changes were actually used. Three categories of TEAM input assumptions were identified for potential in the Chief Joseph sensitivity analysis:

- Unit loading order
- Unit maintenance cycle
- Unit performance (efficiency) involving units with turbine runner replacement

For each of the three categories, the sensitivity analysis compared project generation estimates from one or more pairs of TEAM runs, where the first run of each pair did not include a change in TEAM input assumptions and the second run of each pair did include a change in TEAM input assumptions. The gain or loss in project generation associated with a particular change in TEAM input assumptions was then obtained by computing the difference between the pair of generation estimates. Table 6-4 summarizes the gains and losses (expressed in GWh and aMW) associated with each pair of TEAM runs compared in the sensitivity analysis. The remainder of this section is devoted to identifying the run pairs and summarizing the sensitivity analysis results associated with each category of TEAM input assumptions. The sensitivity analysis results that proved helpful in estimating liquidated damages are also identified.

Table 6-4 Sensitivity Analysis Energy Gains and Losses

Table Row Number	TEAM Run Numbers	Number of New Runners	Number of Units Out For Runner Replacement	Units Out For Runner Replacement	Gain or Loss in Annual Energy	
					GWh	aMW
1	24, 27	16	0	None	------	------
2	24, 28	16	0	None	29.0	3.3
3	16, 29	10	0	None	5.3	0.6
4	16, 30	10	0	None	10.7	1.2
5	16, 31	10	0	None	15.9	1.8
6	16, 32	10	0	None	21.3	2.4
7	16, 33	10	0	None	26.7	3.0
8	24, 34	16	0	None	0.8	0.1
9	24, 35	16	0	None	1.6	0.2
10	24, 36	16	0	None	2.3	0.3
11	24, 37	16	0	None	3.1	0.4
12	24, 38	16	0	None	3.9	0.4
13	24, 39	16	0	None	15.9	1.8
14	1, 40	0	0	None	------	------
15	16, 41	10	0	None	------	------
16	24, 42	16	0	None	------	------
17	16, 43	10	0	None	-5.3	-0.6
18	24, 44	16	0	None	-0.8	-0.1
19	16, 45	10	0	None	-2.7	-0.3
20	24, 46	16	0	None	-1.1	-0.1
21	2, 47	1	0	None	3.3	0.4
22	24, 48	16	0	None	31.0	3.5
23	8, 49	1	2	9, 10	3.2	0.4
24	9, 50	3	2	12, 14	9.9	1.1
25	14, 51	5	2	13, 8	16.0	1.8
26	15, 52	7	2	6, 5	21.3	2.4
27	20, 53	9	2	7, 15	24.6	2.8
28	21, 54	11	2	16, 4	27.6	3.2
29	25, 55	13	2	2, 3	28.7	3.3
30	26, 56	15	1	1	30.4	3.5

Note: TEAM results for Scenarios 27, 40-42 were not used in the Chief Joseph turbine runner replacement study.

6.4.1 Unit Loading Order Sensitivity

One of the input requirements of TEAM consists of the order in which units are assumed to be loaded, where the unit loading order is specified by month. Since the Chief Joseph study would be evaluating runner replacement for units 1-16 but not for units 17-27, the decision was made to load units from units 1-16 and units 17-27 on an alternating basis. The primary reason for using this loading sequence in TEAM was to avoid biasing the study results by favoring one family of units over the other family of units in the selection of the unit loading order.

Unit loading order sensitivity was analyzed for the case where turbine runners are assumed to be replaced on all 16 units from units 1-16. A single pair of TEAM runs [24, 28] was used in the analysis, with Run 24 loading units from units 1-16 and units 17-27 on an alternating basis and sensitivity Run 28 loading units 17-27 first and units 1-16 second. Row 2 of Table 6-4 shows that an annual gain in project generation of 29.0 GWh (or 3.3 aMW) is obtained between Run 24 and Run 28. This represents an increase in annual generation of about 0.2%. The results of the unit loading order sensitivity analysis are consistent with the unit performance data summarized in Figures 4-2 through 4-4. The figures indicate that units 1-16 with new turbine runners have a best-gate efficiency (EBG) of about 92.5%, while units 17-27 with existing turbine runners have an EBG of about 94%. The figures also indicate that the full-gate efficiency (EFG) of units 1-16 with new turbine runners and units 17-27 with existing turbine runners are similar (slightly above 88%) over most of the operating head range. Thus, units 17-27 with existing turbine runners are more efficient than units 1-16 with new turbine runners, with the EBG gain reaching 1.5%. When the unit loading order is changed from alternating units between units 1-16 and units 17-27 (Run 24) to loading units 17-27 ahead of units 1-16 (Run 28), it is reasonable to expect a gain in project annual generation since units 17-27 are more efficient than units 1-16.

6.4.2 Unit Maintenance Cycle Sensitivity

One of the TEAM input options allows the user to specify up to a 5-year outage cycle to account for unit maintenance and other types of unit outages. Using this option, the user is able to specify on a week-by-week basis which units are unavailable. Since benefits for the Chief Joseph study are based on the difference between the results of two TEAM runs (alternative benefits minus base case benefits), it was decided to include only unit maintenance that would change as a result of runner replacement. Information provided by the Chief Joseph Project Office indicated that major maintenance on units 1-16 is performed on a 4-year cycle, while major maintenance on units 17-27 is performed on a 5-year cycle. In order to simplify the study analysis, a 4-year maintenance cycle was used in TEAM for both units 1-16 and units 17-27.

Unit maintenance cycle sensitivity was analyzed for the case where turbine runners are assumed to be replaced on all 16 units from units 1-16. A single pair of TEAM runs

[24, 39] was used in the analysis, with Run 24 assuming a 4-year maintenance cycle and sensitivity Run 39 assuming a 5-year maintenance cycle. Row 13 of Table 6-4 shows that an annual gain in project generation of 15.9 GWh (or 1.8 aMW) is obtained between Run 24 and Run 39. This represents an increase in annual generation of about 0.1%. The small difference in project annual generation between Run 24 and Run 39 suggests that the simplifying assumption that was made in the Chief Joseph study regarding the length of the unit maintenance cycle had a minimal impact on the study results.

6.4.3 Unit Performance Sensitivity – Maximum Output

One of the input requirements of TEAM consists of information that defines the unit performance characteristics of each generating unit that is being modeled. The unit performance characteristics input into TEAM consists primarily of a generator limit and polynomial equations that define unit power and unit overall efficiency, as a function of gross head, under best-gate and full-gate operation. For the Chief Joseph turbine runner replacement study, unit performance characteristics were defined for units 1-16 in existing condition (existing runners), units 1-16 after runner replacement, and units 17-27 in existing condition. A detailed description of the unit performance characteristics used in TEAM is provided in section 4.2.1 and in Appendix A.

Unit maximum output sensitivity was analyzed for two cases involving runner replacement on units 1-16:

- Runner replacement is assumed only for the ten Newport News (NN) units (units 5-14)

- Runner replacement is assumed for all 16 units from units 1-16.

A single pair of TEAM runs [16, 45] was used for the first case, with Run 16 assuming no change in unit maximum output on units 1-16 and sensitivity Run 45 assuming a 1,000-horsepower decrease in unit maximum output on the ten NN units. Similarly, a single pair of TEAM runs [24, 46] was used for the second case, with Run 24 assuming no change in unit maximum output on unit 1-16 and sensitivity Run 46 assuming a 1,000 horsepower decrease in unit maximum output on the six S. Morgan Smith (SMS) units (units 1-4, 15, and 16). The 1,000-horsepower reduction in maximum output for Runs 45 and 46 was accomplished by decreasing the value of the constant term in the unit full-gate power equations by the MW equivalent of 1,000 horsepower.

Row 19 of Table 6-4 shows that an annual loss in project generation of 2.7 GWh (or 0.3 aMW) is obtained between Run 16 and Run 45, while Row 20 of Table 6-4 shows that an annual loss in project generation of 1.1 GWh (or 0.1 aMW) is obtained between Run 24 and Run 46. This represents a decrease in annual generation of 2.7 GWh for the ten NN units with new runners and a decrease in annual generation of 1.1 GWh for the six SMS units with new runners. The larger decrease in annual generation for the NN units, as compared to the SMS units, is largely a result of the NN units receiving runner replacement before the SMS units.

The results of the unit maximum output sensitivity analysis were used to establish dollars per horsepower charges to assess the turbine contractor in the event the replacement runners fail to meet the output specified and guaranteed in the contract. As noted in section 7.7.1, separate dollars per horsepower charges were developed for the NN and SMS units.

6.4.4 Unit Performance Sensitivity – Efficiency

Unit efficiency sensitivity was analyzed for two cases involving runner replacement on units 1-16:

- Runner replacement is assumed only for the ten NN units (units 5-14)
- Runner replacement is assumed for all 16 units from units 1-16

Six pairs of TEAM runs were used for the first case: [16, 29], [16, 30], [16, 31], [16, 32], [16, 33] and [16, 43], with Run 16 assuming no change in unit efficiency on units 1-16, sensitivity Runs 29 through 33 assuming a 0.1% to 0.5% increase in unit efficiency on the ten NN units, and sensitivity Run 43 assuming a 0.1% decrease in unit efficiency on the ten NN units. Similarly, six pairs of TEAM runs were used for the second case: [24, 34], [24, 35], [24, 36], [24,3 7], [24, 38] and [24, 44], with Run 24 assuming no change in unit efficiency on units 1-16, sensitivity Runs 34 through 38 assuming a 0.1% to 0.5% increase in unit efficiency on the six SMS units (units 1-4, 15 and 16), and sensitivity Run 44 assuming a 0.1% decrease in unit efficiency on the six SMS units. The increase in unit efficiency for Runs 29 through 38 and the decrease in unit efficiency for Runs 43 and 44 was accomplished by increasing or decreasing the value of the constant term in the unit best-gate and full-gate efficiency equations by the appropriate amount.

Rows 3-7, 17 of Table 6-4 show the annual gain or loss in project generation that is obtained between Run 16 and Runs 29-33, 43, while Rows 8-12, 18 of Table 6-4 show the annual gain or loss in project generation that is obtained between Run 24 and Runs 34-38, 44. The table results reveal that for the ten NN units with new runners there is a gain/loss in annual generation of 5.3 GWh (or 0.6 aMW) for each 0.1% increase/decrease in unit efficiency. The table results also reveal that for the six SMS units with new runners there is a gain/loss in annual generation of 0.8 GWh (or 0.1 aMW) for each 0.1% increase/decrease in unit efficiency. The larger gain/loss in annual generation for the NN units, as compared to the SMS units, is largely a result of the NN units receiving runner replacement before the SMS units.

The results of the unit efficiency sensitivity analysis were used to establish $/0.1% charges to assess the turbine contractor in the event the replacement runners fail to meet the efficiency specified and guaranteed in the contract. As noted in section 7.7.1, separate $/0.1% charges were developed for the NN and SMS units.

7.0 Economic Analysis

7.1 Overview

The Chief Joseph turbine runner replacement analysis is a collaborative effort between BPA and the CCOE. Collaboration between these agencies is critical because each organization has a somewhat different approach to assessing the viability of hydropower investments. The overall methodology for analyzing hydropower investments is evolving in the Northwest due to these differences in agency perspective and the change in the way investments are funded. Historically, major hydropower analysis work was funded through congressional appropriations. This has changed. BPA is now authorized to directly fund capital hydropower improvements, including the evaluations required to justify such improvements. A collaborative investment evaluation approach insures the objectives of both agencies are met.

A key objective of BPA when evaluating alternative hydropower investments is to determine the project's financial viability. BPA requires the investment to meet an Internal Rate of Return (IRR) equal to or greater than 13% based on the projected stream of benefits and costs including inflation considered over the evaluation period. Additionally, the alternative that maximizes Net Present Value (NPV) is typically identified as the recommended alternative.

The COE has traditionally used a broader perspective for evaluations on the basis of National Economic Development (NED) benefits. For a COE evaluation, the FY 2005 federal water resources discount rate of 5.375% is applied to the un-inflated stream of benefits and costs in order to identify investments with benefit-to-cost ratios (B/C) greater than or equal to 1.0 and which maximize net benefits. The alternative that maximizes net benefits is typically identified as the recommended plan. This turbine runner replacement economic analysis considers the needs of both BPA and the COE.

The incremental economic analysis consists of determining the IRR, NPV, and B/C for each of the sixteen turbine runner replacements one at a time using a spreadsheet model. Additionally, the incremental IRR, NPV, and B/C were determined.

7.2 Analysis

7.2.1 Assumptions

Following are the key assumptions:

- A detailed energy production model that included turbine performance, maintenance schedules, and unit loading order
- Measured existing turbine performance and expected performance for replacement turbines

- 50-year simulated operation with resultant hydrologic flow
- Energy generation separated into three parts: super-peak, heavy load hour (on-peak), and light load hour (off-peak)
- Power price forecasts over the long-term hydrologic period broken into super-peak, heavy load hour (on-peak), and light load hour (off-peak)
- Unit maintenance and loading orders to reflect turbine runner replacements
- Incremental unit analysis
- 35-year investment life (beginning in FY 2005)
- 3% inflation rate on costs
- 5.375% interest during construction (BPA assumption)
- Design, purchase, manufacturing, and installation cost estimates
- 13% discount rate
- 3% inflation of energy values
- No cost contingencies

7.2.2 Runner Replacement Schedule

A runner replacement schedule for all sixteen turbines was developed for the economic analysis (Appendix C). Key schedule assumptions are:

- Contract award and start of model development, May 18, 2006
- Start of manufacturing prototypes, January 12, 2007
- Two-week period for contractor and Chief Joseph staff work prior to releasing the turbine to the contractor for turbine runner replacement.
- 180 days for the contractor work for each turbine
- One week period for Chief Joseph staff work prior to placing the unit in service
- The contractor is working on two units at a time except for the first and last unit

7.2.3 Benefits

Using the COMPARE spreadsheet and the outputs from TEAM and AURORA, the energy benefits (increased revenue) were determined. To determine energy benefits by fiscal year, the schedule in Appendix C was used to find the ratio of months in service to a year. The results are presented in Table 7-1.

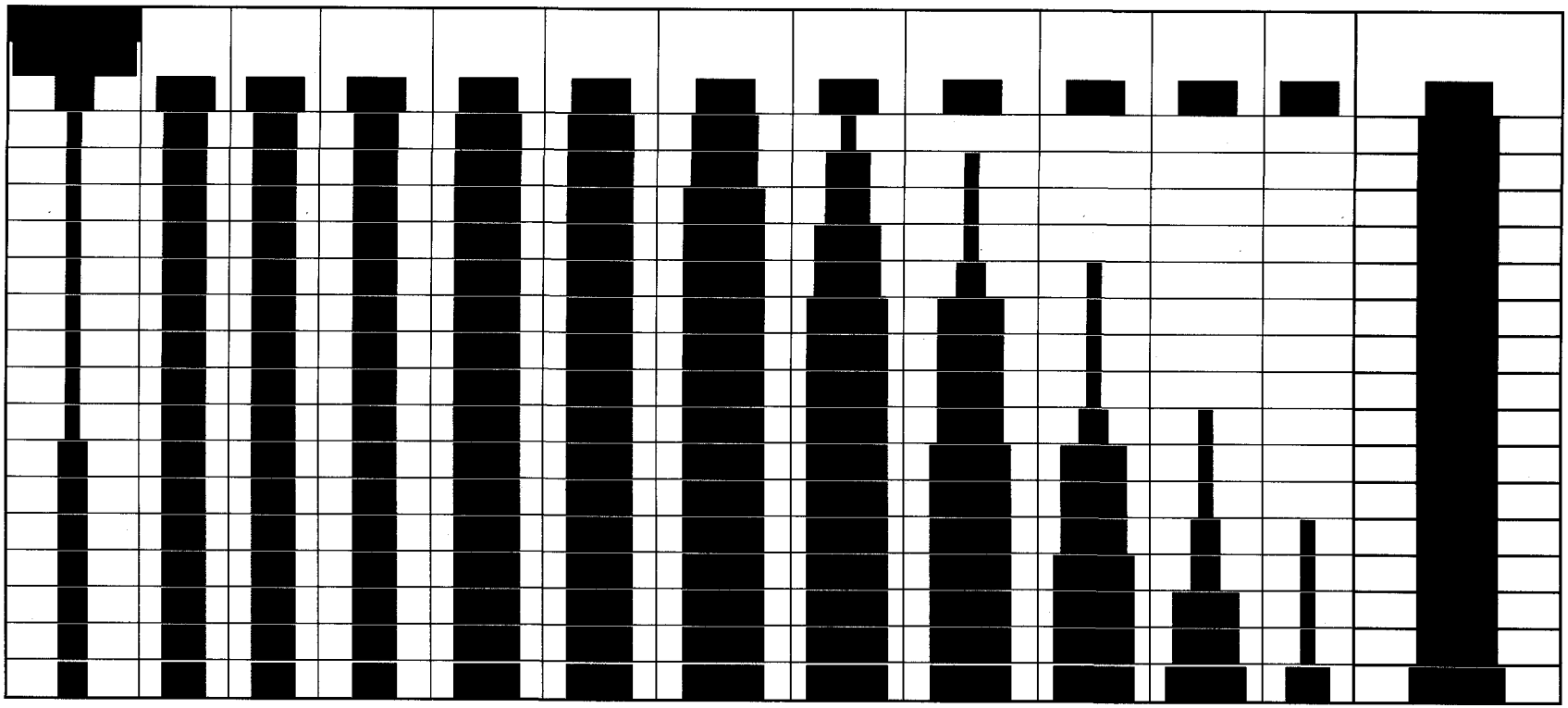
Table 7-1 Incremental Benefits ($1000, Inflated)

Unit	2009 Benefits	2009	2010	2011	2012	2013	2014	2015
11	1,566	1,044	1,613	1,662	1,711	1,763	1,816	1,870
9	1,550		1,597	1,645	1,694	1,745	1,797	1,851
10	1,625		1,674	1,724	1,776	1,829	1,884	1,941
12	1,474		696	1,563	1,610	1,658	1,708	1,759
14	1,350		579	1,432	1,475	1,519	1,565	1,612
13	1,230			1,196	1,344	1,385	1,426	1,469
8	1,140			1,058	1,246	1,283	1,322	1,361
6	963			255	1,053	1,084	1,117	1,150
5	813			216	889	915	943	971
7	641				554	721	743	765
15	433				355	488	502	517
16	333				76	375	386	397
4	359				65	404	416	428
2	314					265	364	375
3	267					200	309	319
1	188						218	225
Total		1,044	6,159	10,752	13,848	15,634	16,516	17,011

7.2.4 Costs

Using the project schedule, 16 individual spreadsheets were created that totaled the inflated costs by fiscal year for engineering and design, engineering during construction, contract supervision and administration, project management, project support, contracting, contractor earnings, interest during construction, and outage cost. Total expected costs by unit and fiscal year are presented in Table 7-2.

[redacted]



7.3 Economic Evaluation Process

The cost and benefit streams were compiled in 16 spreadsheets to calculate the incremental IRR, NPV, and B/C for each individual turbine runner replacement (units 1-16) over the 35-year evaluation period. Additionally the cost and benefit streams were compiled in 15 spreadsheets to calculate the incremental IRR, NPV, and B/C for each additional turbine runner replacement (i.e., from 1 to 2) over the 35-year evaluation period. For these evaluations, costs and benefits were inflated at 3%, Interest During Construction was calculated using 5.375%, and a 13% discount rate was used.

In order to evaluate the robustness of the results, various sensitivity analyses were completed. This was accomplished by changing some variables while holding the others constant. The results are described in section 7.5.

Additionally, to estimate the losses to the FCRPS from contractor failure to meet guaranteed performance, or if the contractor is late in individual turbine runner replacement, spreadsheet models were developed. The results of these analyses are discussed and presented below.

7.4 Economic Results

The results of the incremental analysis are presented in Table 7-3. It shows that when replacing 10 of the 16 turbine runners, the NPV peaks at $28,177,000, the IRR is 22.1%, and the B/C is 1.84. When replacing all 16 turbine runners, the NPV drops to $20,638,000, the IRR is 18.2%, and the B/C is 1.42.

Table 7-3 Incremental Economic Results for IRR, NPV, and B/C

				Incremental Results			
Turbine	IRR	NPV ($1,000)	B/C Ratio	Turbine	IRR	NPV ($1,000)	B/C Ratio
				0 to 1	16.7%	$2,327	1.36
1	16.7%	$2,327	1.36				
				1 to 2	28.1%	$4,831	2.43
2	20.3%	$7,158	1.72				
				2 to 3	26.7%	$4,839	2.29
3	21.9%	$11,997	1.88				
				3 to 4	28.7%	$4,327	2.40
4	23.0%	$16,324	1.98				
				4 to 5	26.3%	$3,677	2.19
5	23.4%	$20,001	2.01				
				5 to 6	23.9%	$2,908	1.98
6	23.5%	$22,908	2.01				
				6 to 7	21.7%	$2,374	1.78
7	23.3%	$25,282	1.98				
				7 to 8	21.0%	$1,786	1.71
8	23.1%	$27,067	1.95				
				8 to 9	17.6%	$1,036	1.40
9	22.7%	$28,103	1.91				
				9 to 10	13.3%	$73	1.03
10	22.1%	$28,177	1.84				
				10 to 11	7.1%	[redacted]	0.56
11	21.1%	$26,730	1.72				
				11 to 12	7.2%	[redacted]	0.58
12	20.4%	$25,727	1.65				
				12 to 13	8.0%	[redacted]	0.63
13	19.9%	$24,851	1.60				
				13 to 14	5.9%	[redacted]	0.51
14	19.3%	$23,658	1.54				
				14 to 15	4.7%	[redacted]	0.44
15	18.7%	$22,307	1.48				
				15 to 16	1.7%	[redacted]	0.30
16	18.2%	$20,638	1.42				

7.5 Sensitivity Analysis

The results of the sensitivity analysis presented in Table 7-4 show that the base case is robust when replacing the runners in the first family of 10 units.

[redacted]

7.6 Other Considerations

7.6.1 Reliability Considerations

A material condition for all 16 turbines was determined for all 16 turbines in hydroAMP. They were all rated in "good" condition despite approaching 50 years of age. Because the turbines were rated in good condition, failures are not likely and reliability was not modeled (since turbine-caused forced outages are unlikely). The units that have their runners replaced will have all wearing parts inspected and repaired or replaced as required. This should inherently improve the reliability of these units.

7.6.2 Maintenance

Rehabilitation of some or all of the turbine units at the same time provides maintenance cost benefits. Not only will the equipment need less maintenance in the future, but the maintenance can also be provided at lower cost. The standardization of equipment during a single rehabilitation effort reduces needed parts inventories and cuts the amount of staff training required. Due to the above reasons, it is generally considered desirable to replace the turbine runners in complete families if justified.

7.6.3 Operational flexibility

In order to balance unit operational hours with other Powerplant factors such as heating needs and transmission limitations, the most efficient units at Chief Joseph are not always loaded. This results in less than maximum generation from the plant. If all units have

near the same performance levels in terms of efficiency, it will no longer be an issue which units are loaded or the order in which they are loaded.

7.6.4 Environmental Considerations

No significant environmental impact is anticipated from the replacement of runners in turbine units 1-16 at Chief Joseph Dam.

Impacts that may occur during construction and installation or from operations include:

- The flow regime will be minimally changed.
- Maximum hydraulic capacity of the project will be minimally changed from the existing situation.
- On-site construction should not cause any impact that is not otherwise experienced during normal routine operations and maintenance activities.
- Off-site impacts would be those associated with manufacturing and shipping of new runners and the disposal of existing runners.

7.7 Liquidated Damages

7.7.1 Overview

Separate analyses were completed to estimate the costs to the FCRPS if work is completed later than agreed to, or if the guaranteed performance values are not met. The purpose of these analyses is to estimate, for inclusion in the turbine runner replacement contract, what the costs are to the FCRPS for: 1) delay in completion of the work, or 2) delivery of products that do not perform at the level specified and guaranteed in the contract.

Specific categories of failures include:

1. Late Completion - If the contractor is late in returning a unit for energy production, this results in forgone energy production. The duration for these outages is provided by the contractor in its proposal, and is a factor that determines the NPV of the proposal. The NPV of the proposal is one of the evaluation factors used in determining Best Value. The value per date late is calculated using the values from the TEAM analyses. It is comprised of two values: the daily value for the unit out of service and the daily value from the increased energy generation. The value for the NN and the SMS units is the average of the sum of the two daily values as shown in Table 7-5. The calculated values are: for the NN turbines, $6,013/day, and for the SMS turbines, $3,453/day.

[redacted]

2. Horsepower (hp) might be below the minimum guarantee (120,250 hp) established in the contract. This calculation is based on the TEAM estimate of revenue loss associated with horsepower, reduced by 1,000 horsepower for each family. This value is used to calculate the Present Value (PV) for each family over 35 years, using 3% inflation and discounted at 13%. The results are divided by 1,000 to determine a per hp value. The value for the NN units is $72.18/hp and for the SMS units $43.86/hp. The analysis assumes for the SMS units that the NN units meet the horsepower guarantee.

3. Efficiency (0.1%) might be below the minimum guarantee (94%) required by the Request for Proposals (RFP). The RFP requires a minimum efficiency, but allows the contractor to propose turbine runners with increased efficiency. The efficiency is provided by the contractor in the proposal, and is a factor that determines the NPV of the proposal. The NPV of the proposal is one of the evaluation factors used in determining Best Value. This calculation is based on the TEAM estimate of energy loss associated with efficiency, reduced by 0.1% for each family. The analysis assumes for the SMS units that the NN units met the efficiency guarantee. This would be assessed based on the TEAM estimate of energy loss associated with the reduced efficiency of each family. The decrease in energy from the model run for each family of turbines is divided by the number of turbines in that family to determine an average per-turbine value. This value is used to calculate the PV for each family over 35 years, using 3% inflation and discounted at 13%. The value for the NN units is $235,798/0.1% and for the SMS units $50,354/0.1%.

4. Cavitation damage after 2 years might be greater than the cavitation limits specified in the contract, which the contractor guarantees to meet. After 2 years of commercial operation, the turbine will undergo a joint inspection and measurement of the cavitation damage. If the cavitation damage does not meet the guarantee, the contractor is required to repair the damage and has an opportunity to resolve the cause of cavitation. After another 2 years of commercial operation the turbine will again undergo a joint inspection and measurement of the cavitation damage. If the cavitation damage does not meet the guarantee, damages will be assessed. If the damage is less than the contract guarantee during the initial inspection and measurement, there is no further action.

The benefits calculated for turbine runner replacement assumes that the major maintenance outage will decrease from once every 4 years for 8 weeks, to once every 5 years for 4 weeks. Currently $12,500 per major maintenance outage is expended for cavitation repair; no cavitation repair is expected from turbines that meet the cavitation guarantee.

To calculate the costs from missing the cavitation guarantee it was assumed the maintenance outage would occur every 4 years for 6 weeks and $12,500 per maintenance outage is expended for cavitation repair.

For the NN units it was assumed that none of the NN units met the cavitation guarantee and an additional 14 days of outage are required. This outage is valued at a daily rate from Table 7-5 with an assumption that $50,000 was expended per year for the four units. The values were inflated at 3% and discounted at 13% over 35 years. An average per-unit value was calculated by dividing the result by 10. The calculated value is $362,905 per unit.

For the SMS units it was assumed that no SMS units met the cavitation guarantee and an additional 14 days of outage are required. This outage is valued at a daily rate that is the average of the rates for the NN and SMS units from Table 7-5, and assumes that $12,500 was expended per unit. The values were inflated at 3%, and discounted at 13% over 35 years. An average per-unit value was calculated by dividing the result by 6. The calculated value is $320,975 per unit.

7.7.2 Value of Turbine Efficiency Greater than Guaranteed Minimum

Table 7-6 is included to assist potential turbine runner replacement contractors in their assessment of whether or not to attempt to construct the new turbine runners to be more efficient than the minimum required in the contract. The table summarizes the estimated NPV of an increase in turbine efficiency of 0.1, 0.2, 0.3, 0.4, and 0.5% for the NN units and SMS units. The value for the SMS units assumes the NN units are replaced at 94%. All variables were held constant for this analysis (costs, outage duration, etc.).

Table 7-6 NPV of Increased Efficiency over Contract Guarantee ($1000)

Percent increase	NN	SMS
0.1%	2,329.1	487.3
0.2%	4,571.6	958.3
0.3%	6,881.4	1,494.4
0.4%	9,008.4	1,981.7
0.5%	11,810.0	2,560.8

8.0 Recommendations

8.1 Recommended Economic Choice

The recommended economic choice is to replace runners in the ten Newport News turbine units (units 5-14). The incremental benefits for the S. Morgan Smith units do not support runner replacement at this time. Replacing the runners in the Newport News units has an expected IRR of 22.1% and a NPV of $28.2 million based on current (2005) dollar levels with an assumed inflation rate of 3%.

The Economic Analysis Team further recommends that the procurement contract be structured for acquisition and installation of the Newport News units with an option for the S. Morgan Smith units that can be exercised within 5 years of award.

After receiving prices and guaranteed turbine performance through the contracting process, the values should be used in another analysis to determine if they are justified.

8.2 Contracting Schedule

[redacted]

8.3 Balance of Plant

As part of this evaluation, a separate balance of plant/uprate study was conducted by HDC to determine if all power train components were adequate for the unit ratings assumed in this improvement study. The following concerns were raised in the study:

- Units 1-4, 13-16 rotor fans may have a resonant frequency that should be changed – estimated cost $86,000.
- Stator leads for units 1-16 need to be reinsulated.
- Stator air coolers for units 1-16 may be undersized – no cost estimate is available as the units do not have an operational history of a temperature problem.
- Units 1-16 generator current transformers are under-rated by 2.4%.

- Iso-phase buss for units 1-16 – these were purchased using different specifications than would be used today. The momentary rating is unknown and may result in a failure under fault conditions – estimated cost $3,400,000.

All of these conditions were present before this study was conducted and would need to be separately justified if the project determines they are high priority items.

Additionally, the stators for all 16 units are at the age where they should be rewedged. It may be appropriate to accomplish this task, using routine expense funding, concurrently with the turbine runner replacements.

An additional intake bulkhead is required to allow the contractor to have two units out of service at a time. This cost is included in the overall cost estimate used in this economic evaluation.

Appendix A Turbine Performance Information

S. Morgan Smith Units 1-4, 15, 16 Existing performance A-60
Newport News Units 5-14 Existing performance A-60
S. Morgan Smith Units 1-4, 15, 16 New Turbine Performance A-61
Newport News Units 5-14 New Runner Performance A-61
Chief Joseph Newport News Units 1-4, 15, 16 Existing performance (Generator output) A-62
Chief Joseph Newport News Units 1-4, 15, 16 Existing performance (Overall efficiency) A-62
Chief Joseph Newport News Units 5-14 Existing performance (Generator output) . A-63
Chief Joseph Newport News Units 5-14 Existing performance (Overall efficiency) A-63
Chief Joseph S. Morgan Smith Units 1-4, 15, 16 New performance (Generator output) A-64
Chief Joseph S. Morgan Smith Units 1-4, 15, 16 New performance (Overall efficiency) A-64
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Tailwater curve, Chief Joseph Dam 1990-2000 ..... A-67

[redacted]

Appendix B Turbine Energy Analysis Model (TEAM)

The Turbine Energy Analysis Model (TEAM) was used to determine the energy production that could be expected at the Chief Joseph powerplant for both existing conditions and potential turbine runner replacements. TEAM was developed by the Economic Analysis Team (EAT) as part of the Chief Joseph Turbine Runner Replacement study.

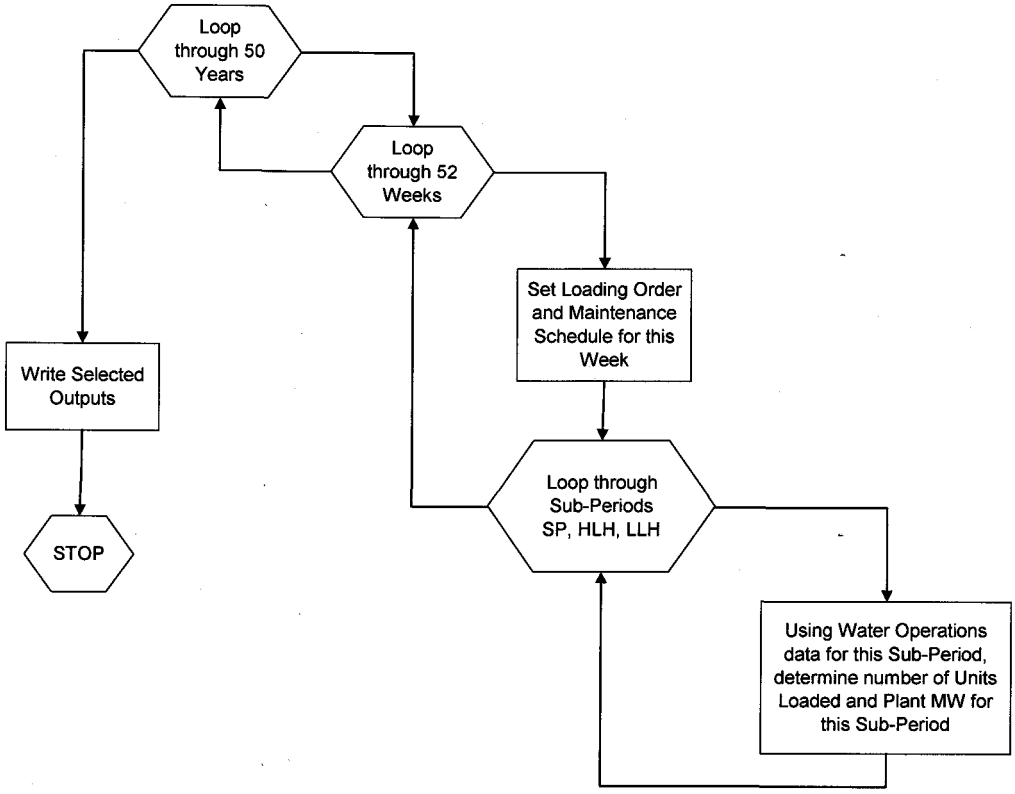
In a previous study done for McNary powerplant, two separate models were used to evaluate energy production. One model was the FORTRAN-based Energy Hydropower Allocation (HALLO) Model and the other was a spreadsheet-based model known as the McNary Uprate Study Team (MUST) VI Spreadsheet Tool. Both models determined generation over a long-term period (50 to 60 years) with each year broken into 14 sub-periods (12 months with April and August each split into two periods). Each of these models had its own particular strengths. HALLO provided a more detailed representation of turbine performance curves on a unit-by-unit basis, the ability to define specific loading orders, and a specific unit-by-unit maintenance schedule. While HALLO determined average monthly generation, MUST incorporated the ability to break monthly generation into three sub-periods important for valuing power: Super Peak (SP), Heavy Load Hour (HLH), and Light Load Hour (LLH). In addition, because MUST was spreadsheet-based it was relatively easy to use and process the output as well as being extremely portable.

Based on lessons learned in the McNary Uprate Study, the Economic Analysis Team decided to develop and use one model that built on the strengths of both HALLO and MUST. The result of this effort was TEAM. TEAM is an Excel-based spreadsheet that uses the same sub-periods as MUST and uses Visual Basic for Applications to incorporate much of the HALLO logic. In addition, while both MUST and HALLO used monthly time steps, TEAM was further refined to use a weekly time step.

TEAM Overview

As discussed above, TEAM was derived from two models used in the MUST study. In addition, TEAM was developed to allow each year to be broken into 52 weeks rather than just the 14 periods used in the McNary Uprate Study. In addition, each week is further broken into the three sub-periods used in MUST (SP, HLH, and LLH). A simplified logic diagram of TEAM as used for the Chief Joseph evaluation is shown in Figure B-1. A detailed logic diagram, Figure B-3 is shown at the end of this appendix.

Figure B-1 - TEAM Logic Flow



Once all inputs are defined within the TEAM spreadsheet, the user begins execution of TEAM. When executed, TEAM loops through all years in the long term hydrology; within each year, TEAM then loops through each week and within each week TEAM loops through the three sub-periods starting with Super-Peak, then Heavy Load Hours, and finally Light Load Hours. For each sub-period, TEAM uses the defined flow and head for that sub-period and loops through the units based on the loading order specified for that week while checking the maintenance schedule for unit availability and loads as many units as needed to fully utilize the sub-period flow.

TEAM used the logic developed in the HALLO model to allocate project discharge for each sub-period to units at a powerplant with multiple and/or different-sized generating units. When the discharge allocation has been determined for each generating unit, the power output for each unit is computed based on the head and unit efficiency specified. Using available discharges adjusted for various project flow losses, TEAM simulates the loading of generating units in a given sequence, up to the point that all discharge is utilized for generation and any excess is spilled. The unit loading order sequence is specified for each week of the year, thereby allowing the model to reflect variations in loading order and unit availability.

TEAM utilizes unit performance curves to determine the power, efficiency, and discharge of each available unit at the lower and upper limits of operation. The lower limit of operation is obtained from a unit performance curve representing unit operation at the Best Efficiency Point (BEP). The upper limit of operation is established by considering several factors that can restrict unit output, including the generator limit, the upper 1% limit, and the cavitation limit. Unit operations at the upper 1% limit and at the cavitation limit are each obtained from a unit performance curve. Although not utilized in this study, during the fish passage season, units can be required to operate to within 1% of the BEP; outside the fish passage season, units are allowed to operate up to the cavitation limit as long as the generator limit is not exceeded. Whether or not to use the 1% limit can be defined on a week by week basis. TEAM utilizes a multi-step loading process to allocate project discharge between the available units. This process, which is carried out for each sub-period (SP, HLH, and LLH) on a weekly time step for the hydrologic period of record, is briefly summarized below.

1. Determine the project head and discharge available for power generation.

2. Determine which units are unavailable for generation due to either scheduled or forced outages.

3. Apply the head to the appropriate unit performance curves to determine for each available unit the power, efficiency, and discharge at the lower and upper limits of operation.

4. Taking into account the specified loading order and the project discharge, determine which of the available units can be loaded at the BEP (the lower limit of operation) for the entire period.

5. If there is sufficient project discharge to load the units identified in the previous step above the BEP for the entire period, uniformly load all identified units as far above the BEP as the project discharge will allow, without exceeding their upper limit of operation.

6. If the previous step has not exhausted the project discharge and at least one available unit has not already been loaded, utilize the remaining discharge to load the next available unit at the BEP for as much of the period as the remaining discharge will allow.

7. The dispatch of the available units by TEAM is now finished. If the previous step has not exhausted the project discharge, any remaining discharge is spilled.

Once the final loading discharge has been determined for each utilized generating unit, TEAM then computes the corresponding power output and efficiency for each unit. This is done by simultaneously solving for P and E in the following pair of equations, which together are used to represent unit operation between the lower and upper limits of operation.

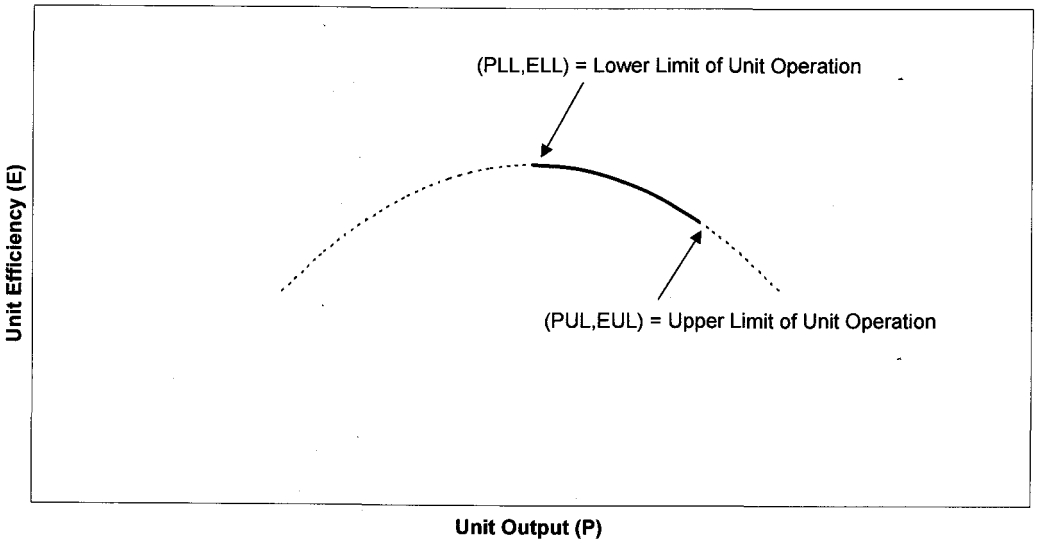
$$P = \frac{H * Q * E}{11.82}$$

$$\frac{E - ELL}{EUL - ELL} = \left(\frac{P - PLL}{PUL - PLL}\right)^2$$

where: H = available head (in feet)
Q = unit discharge (in cfs)
E = unit efficiency (in %)
P = unit output (in kW)
ELL = unit efficiency at the lower limit of operation (in %)
EUL = unit efficiency at the upper limit of operation (in %)
PLL = unit output at the lower limit of operation (in kW)
PUL = unit output at the upper limit of operation (in kW)
11.82 = product of the horsepower constant (550 ft-lbs/sec) and the kilowatt conversion factor (1.341 hp/kW) divided by the density of water (62.4 lb/ft^3)

The first equation above is the standard hydropower equation, while the second equation above represents a parabola in P and E that passes through the points (PLL, ELL) and (PUL, EUL), as shown in Figure B-2 below. Since the lower limit of operation in BEP corresponds to unit operation at the BEP, the point (PLL, ELL) corresponds to the highest point on the parabola.

Figure B-2 - TEAM Unit Efficiency versus Output



The calculations described above are done for all sub-periods (SP, HLH, and LLH) on a week-by-week basis. For the first two sub-periods, if flow remains after all units have been loaded up to their maximum limit, remaining flow is moved to the next sub-period (from Super-Peak to Heavy Load and from Heavy Load to Light Load). For the last sub-period (Light Load), if flow remains, all sub-periods are set to the weekly average flow and any unused flow (spill) is assumed to occur in all sub-periods. After all the years are completed depending on selected output, then power generation, total flow, power flow, unutilized power flow, gross head, tail water, and overall efficiency are output for each sub-period to the TEAM spreadsheet. In addition, if selected, unit-specific output is available for each sub-period.

Run Execution

Run Execution is controlled on Worksheet "Control." The number of years included in the input data is set here as well as the number of periods (in this case weeks) in the year. The user can select the first and last year to run (anywhere from one to the total years available can be selected). The user can choose whether to run sub-periods or only use period average data. Run identifiers are also entered here. The user can select desired outputs here. The user can also choose to have Run Status messages written to this worksheet during TEAM execution. A prefix is entered for naming output worksheets. If the user decides to save the file, a unique file name based on run date and time and the run identifier is created. After the file is saved, the file name and time it is saved is written to this worksheet.

TEAM Inputs

Key input data utilized by TEAM is listed below, and a more detailed description follows.

- Unit performance curves
- Unit loading order sequences
- Maintenance unit outage sequences
- Project regulated flow
- Project forebay elevation
- Project tailwater rating curve
- Sub-period definitions
- Project flow losses (if applicable)
- Percent of project flow spilled for fish (if applicable)
- Upper limit on project flow spilled for fish (if applicable)
- Powerhouse minimum flow requirement (if applicable)
- Unit performance losses due to fish screens or other devices (if applicable)
- Unit operating constraints (if applicable).

Unit Performance Data

TEAM requires detailed information for combined turbine and generator performance for each type of unit included in the evaluation. For each unit, TEAM requires four polynomial equations (up to the 3rd order) that are each a function of gross head. These are Power (MW) at Best Gate (PBG), Power (MW) at Full Gate (PFG), Efficiency (%) at Best Gate (EBG), and Efficiency (%) at Full Gate (EFG). In addition, four points (starting head, starting MW, ending head, and ending MW) are included to define an upper cavitation limit. This data is included in the TEAM spreadsheet on worksheet "Unit Performance." This sheet also includes the total number of units for the powerplant (27 for this study) and the number of different types of units (five used in this study). The unit type for each unit is assigned on worksheet "Unit_Operations."

Loading Order

For TEAM to load units for each sub-period, it needs to know the desired loading order. It is recognized that loading order and the number of hours each unit is loaded can vary by time of year. Loading orders used are entered into TEAM on worksheet "Unit_Operations." TEAM allows input of up to 14 different loading orders. The loading order assigned to each week is also entered on worksheet "Unit_Operations."

Maintenance

TEAM allows up to a 5-year maintenance/unit outage cycle to be entered on a week-by-week basis specifying which units are unavailable for that week (from one to the entire plant if desired). For studies whose period of record exceeds the number of years in the cycle, TEAM repeats the cycle restarting at the first year in the cycle that was used. This data is entered into TEAM on worksheet "Unit_Operations."

Water Operations / Hydrology

TEAM requires water operation data for each week for every year evaluated. This is derived from long-term flow data output from models such as HYSSR or HYDROSIM. TEAM can use up to 60 years of data. HYSSR and HYDROSIM provide operation data for 14 periods a year (12 months with April and August each split into two periods). One of the data items needed is the average flow for each period. TEAM derives the average weekly flow by using the monthly flows. If a week occurs entirely within one month, the average flow for that month is used for the week. If a week crosses two months, a weighted average based on the number of days of the week that occur in each of the two months is used to estimate the weekly flow. If weekly flows are available from a different source, they can be substituted for the weekly flows TEAM calculates.

In addition, the forebay elevation is also needed for TEAM. This can either be entered for each month in the study or one constant number can be entered. In this evaluation a constant forebay elevation was assumed.

Although not used in this evaluation, TEAM also allows flows for losses or non-power releases such as lockage, fish spills, and minimum period releases to be entered for each month/week. One set of values is used for all years if included.

A tailwater curve is also included as part of this data. All of this data is entered on Worksheets "Water_Monthly" and "Water_Weekly."

Sub-Periods

After weekly flow data is developed, it needs to be converted to the sub-period flow. This is done using shaping factors. These factors are entered into TEAM on Worksheet "Sub_Period_Monthly_Factors." These factors are generally available for 14 periods similar to the original water operation data, and can be converted to weekly factors in a manner similar to the water flows. These factors are calculated on Worksheet "Sub_Period_Weekly_Factors." These weekly factors are then used to calculate the average sub-period flows on Worksheet "Sub_Periods." If weekly factors are available, they can be used in place of converting the monthly factors to weekly factors. If users have specific sub-period flows they want to use, they can replace the sub period flows calculated by TEAM in the "Water Weekly" sheet.

Other Inputs

Although not used in this evaluation, TEAM does allow additional constraints to be entered for powerplant operations. These include derating units, accounting for unit performance losses due to fish screens, and limiting unit operation to within 1% of the Best Efficiency Point. All of this data is entered on Worksheet "Unit_Operations."

Run execution is controlled on Worksheet "Control." The number of years included in the input data is set here, along with the number of periods (in this case weeks) in the year. The user can select the first and last year to run (anywhere from one to the total years available can be selected). The user can choose whether to run sub-periods or only use period average data. Run identifiers are also entered here. The user can select desired outputs here. The user can also choose to have Run Status messages written to this worksheet during TEAM execution. A prefix is entered for naming output worksheets. If the user decides to save the file, a unique file name based on run date and time and the run identifier is created. After the file is saved, the file name and time it is saved is written to this worksheet.

TEAM Outputs

Four types of output can be selected. Each type (except Debug) is written to its own Worksheet. Desired output and corresponding worksheet names are set in Worksheet "CONTROL."

Output Types:

Detailed Unit Output	Provides period-by-period detailed loading information. Only for monthly data of 10 years or less.
Quick Unit Output	Added to VB version as an alternative to the existing detailed unit output. Provides abbreviated period-by-period output. Much quicker than detailed unit output.
Table Output	User-friendly tabular output used for project evaluations. Available for individual sub-periods and runs based on period average flows without sub-periods. A sub-period summary table is also produced.
Debug	These were the embedded write statements used for debugging included in the original HALLO. Included for user familiarity. Written to its own text file.

The Table Output for hydrologic period of record tables includes:
(available for sub-periods (SP, HLH, and LLH) as well as average weekly)

- Project forebay elevation
- Project tailwater elevation
- Project available head
- Project regulated flow
- Flow available to the powerhouse
- Flow utilized by the powerhouse
- Flow not utilized by the powerhouse (forced spill)
- Powerhouse overall efficiency
- Powerhouse total generation.

The Detailed Unit Output consists of period-by-period information that summarizes the lower and upper limits of unit operation and indicates how the model loaded each unit. This detailed information can be particularly useful when studying alternatives that involve generating units of different types and/or sizes.

Figure B-3 – Detailed TEAM Logic Flow

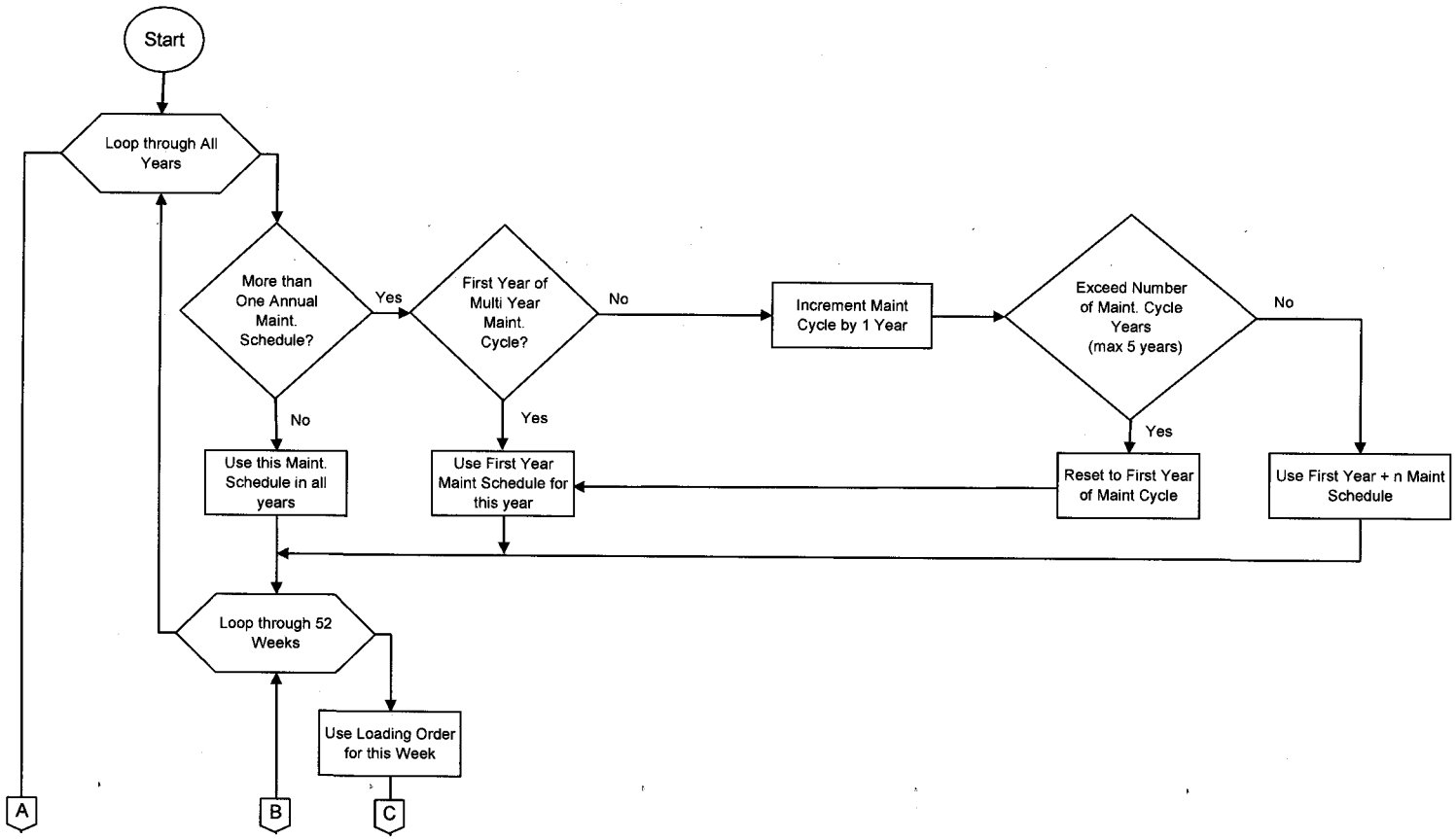


Figure B-3 – Detailed TEAM Logic Flow (continued)

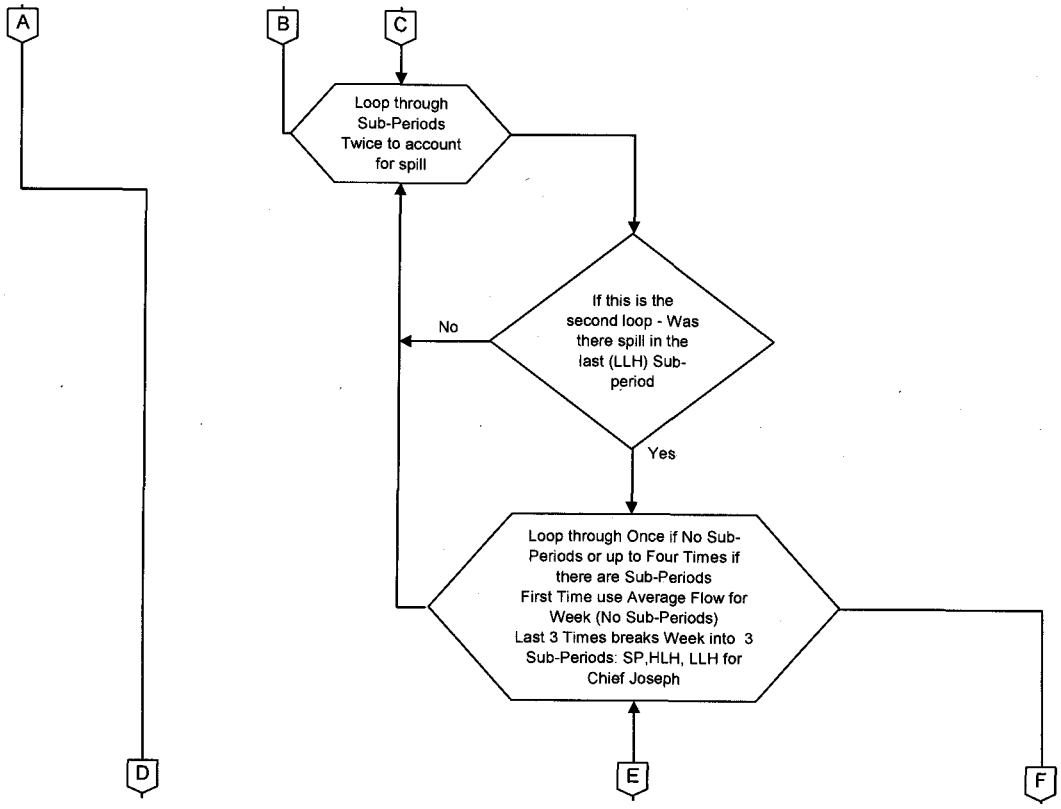


Figure B-3 – Detailed TEAM Logic Flow (continued)

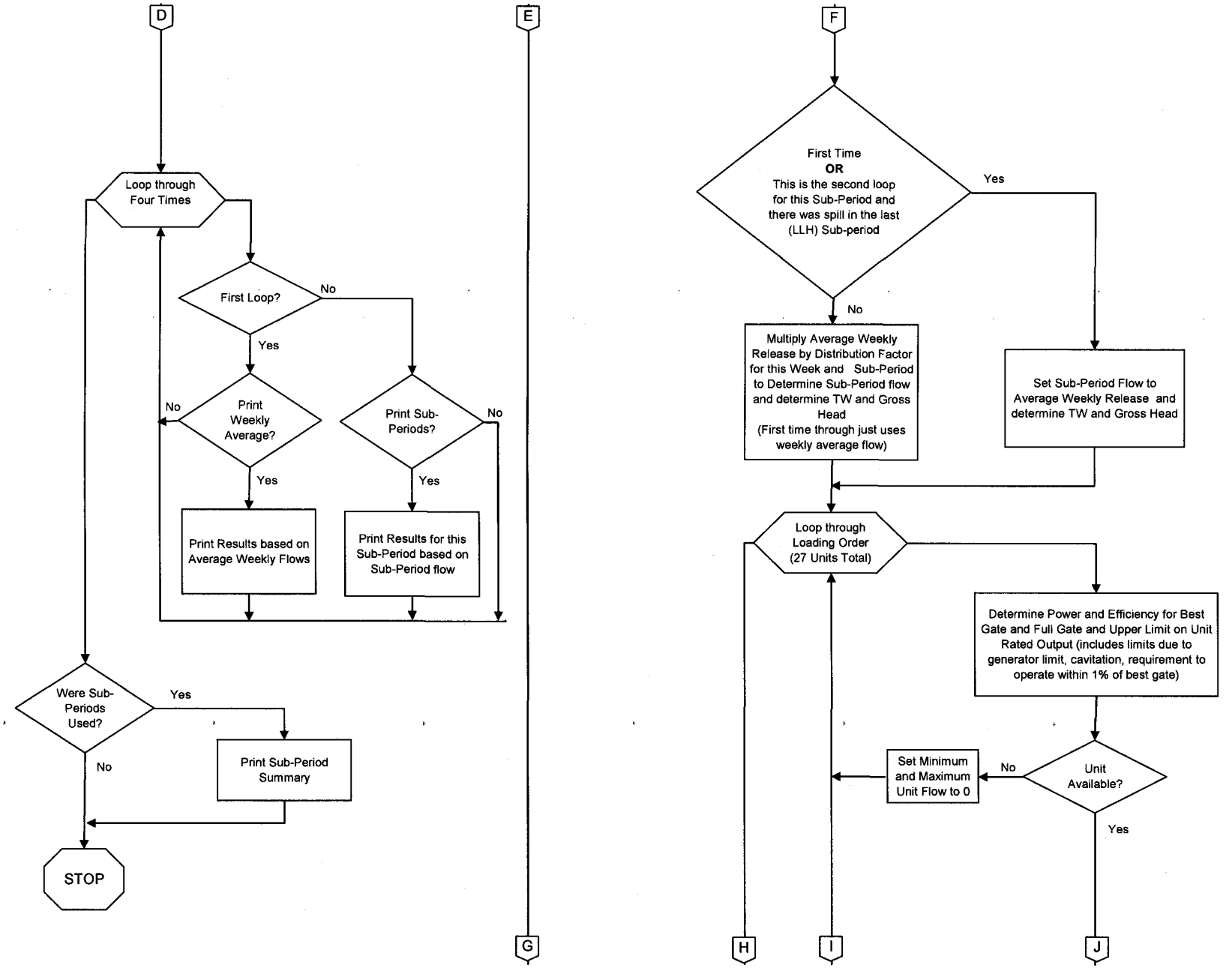


Figure B-3 – Detailed TEAM Logic Flow (continued)

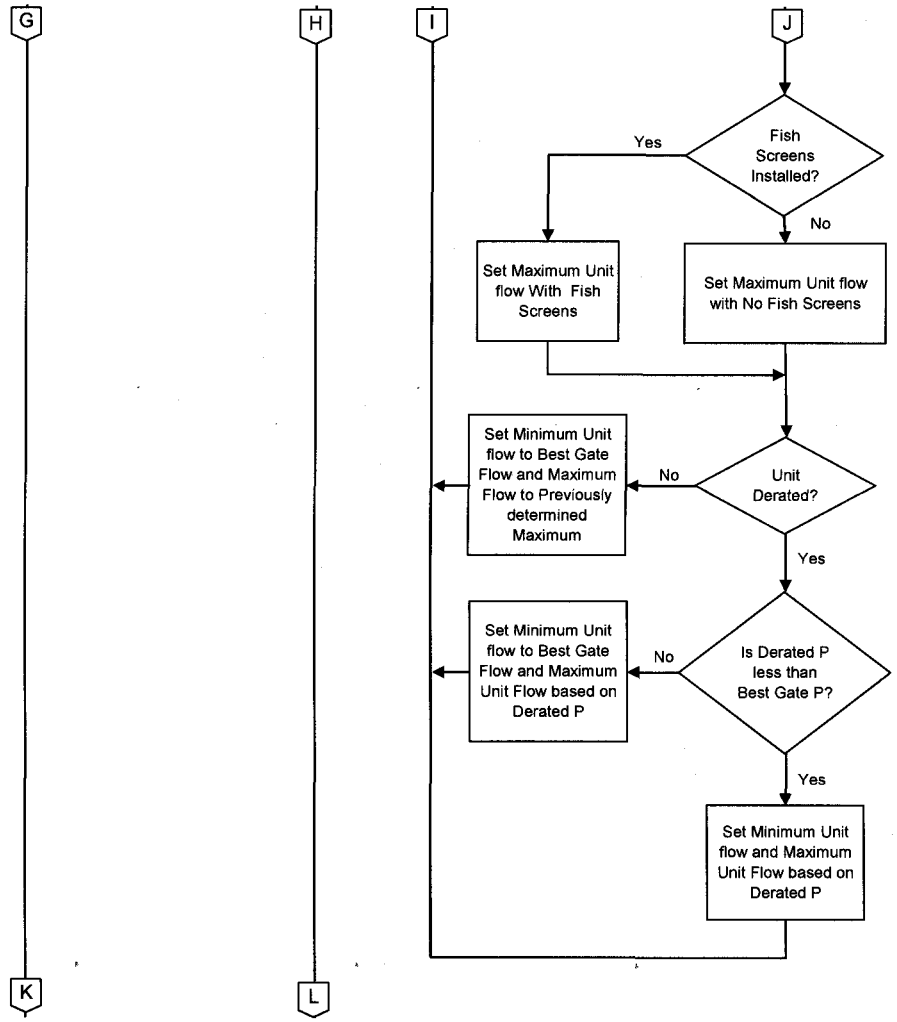


Figure B-3 – Detailed TEAM Logic Flow (continued)

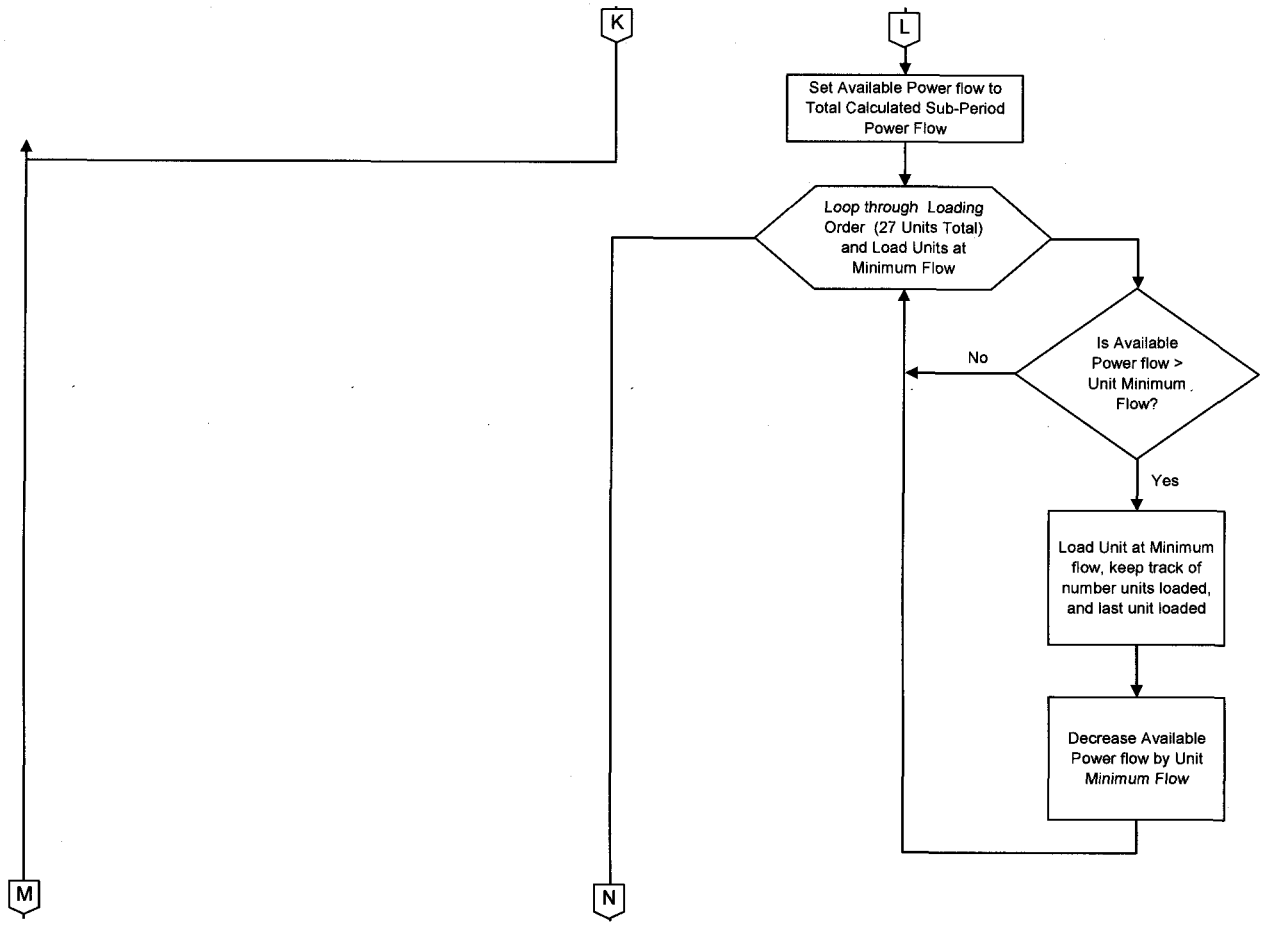


Figure B-3 – Detailed TEAM Logic Flow (continued)

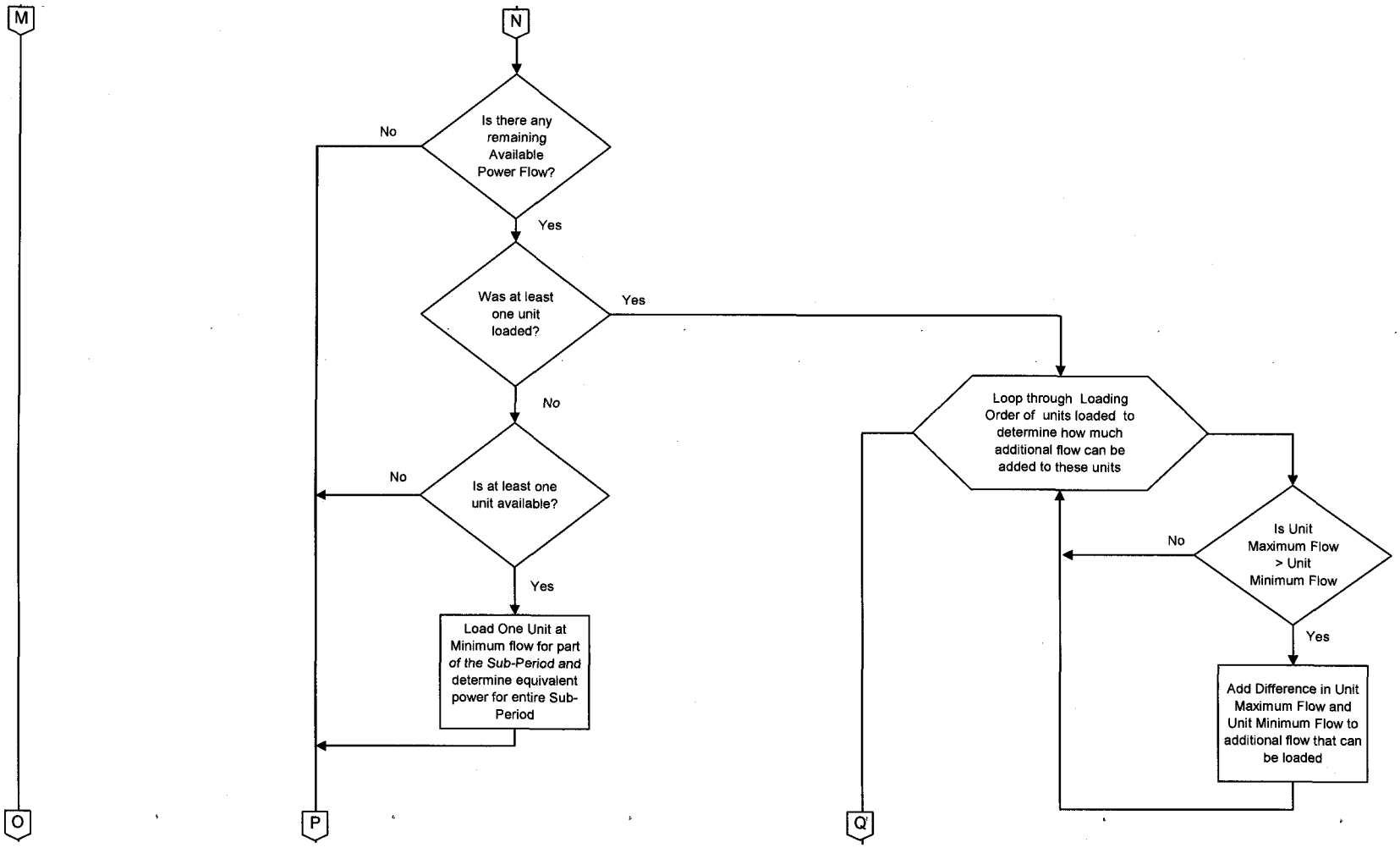


Figure B-3 – Detailed TEAM Logic Flow (continued)

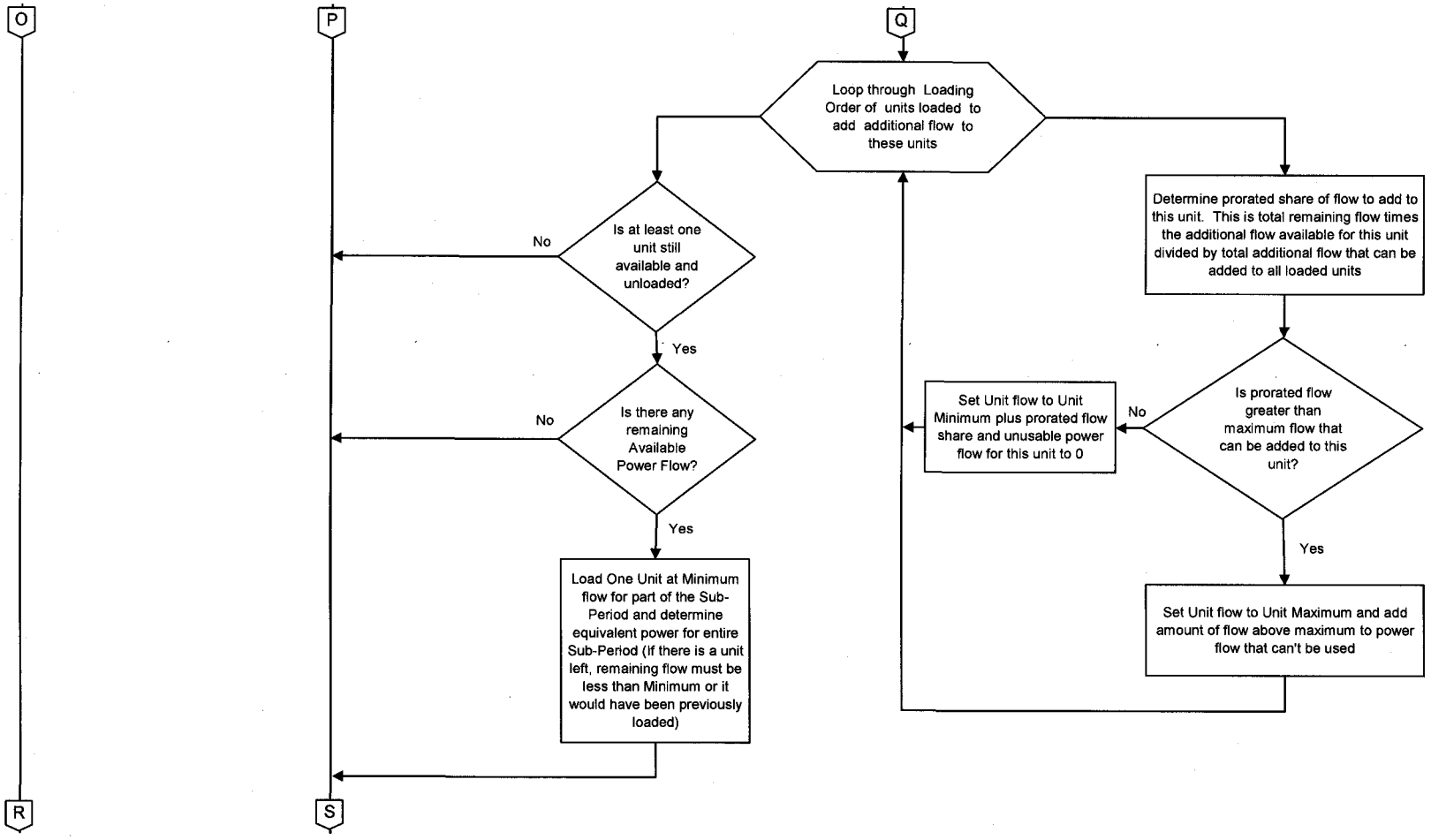


Figure B-3 – Detailed TEAM Logic Flow (continued)

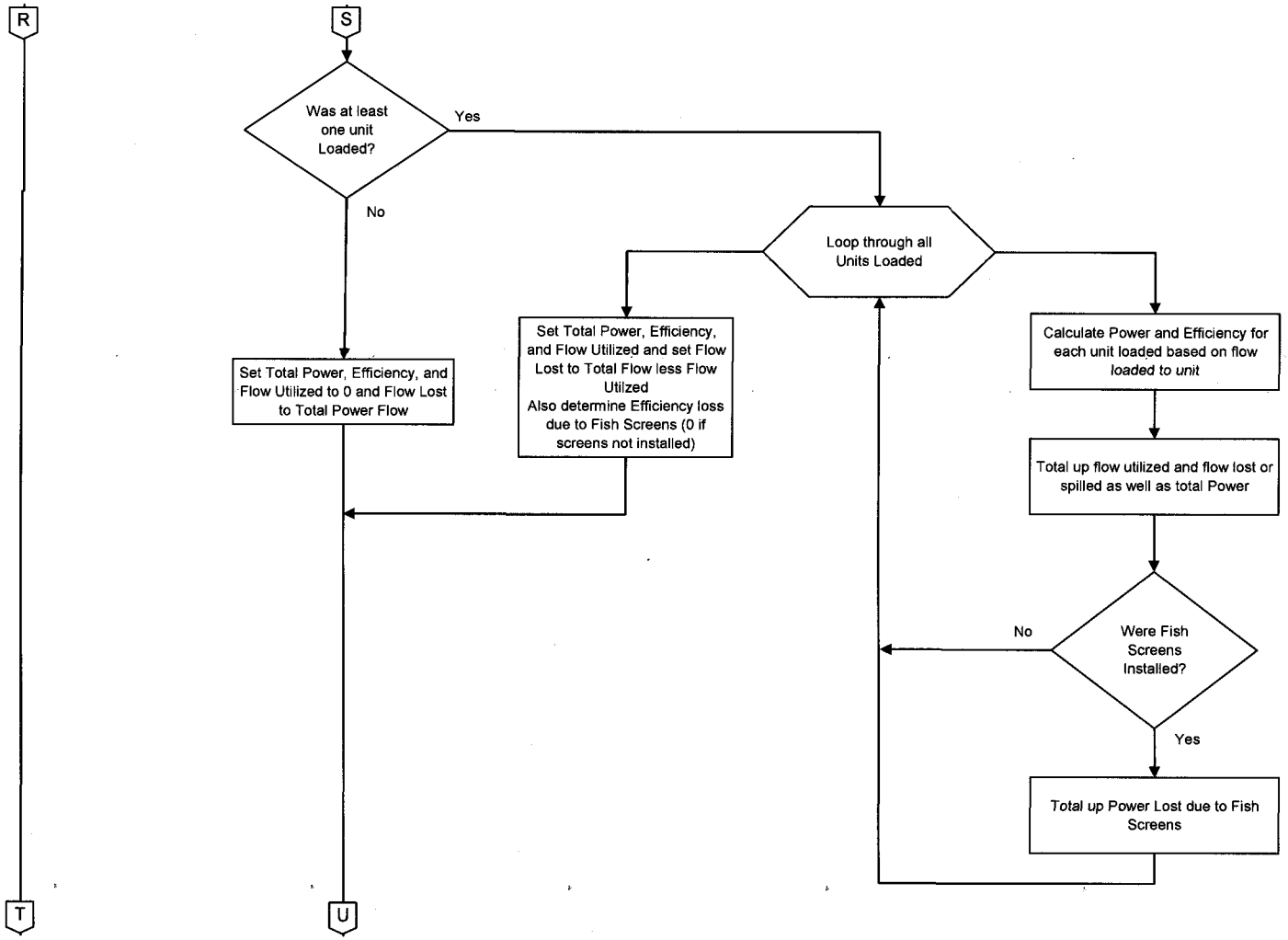


Figure B-3 – Detailed TEAM Logic Flow (continued)

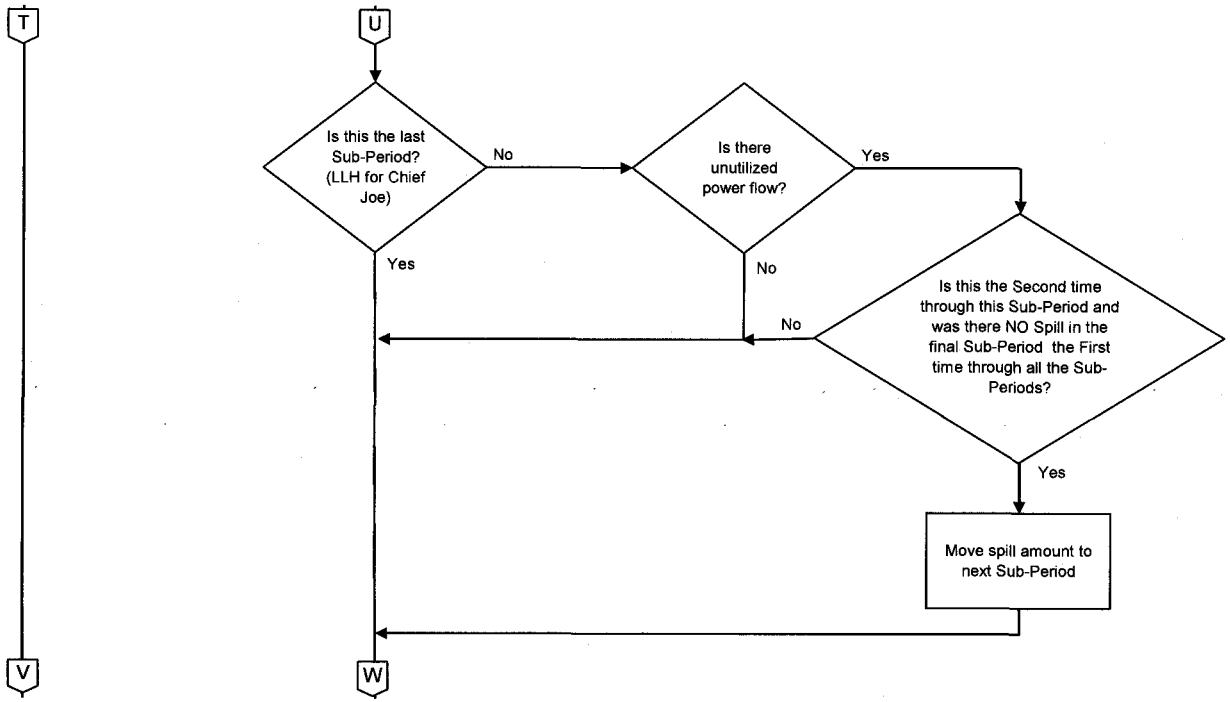
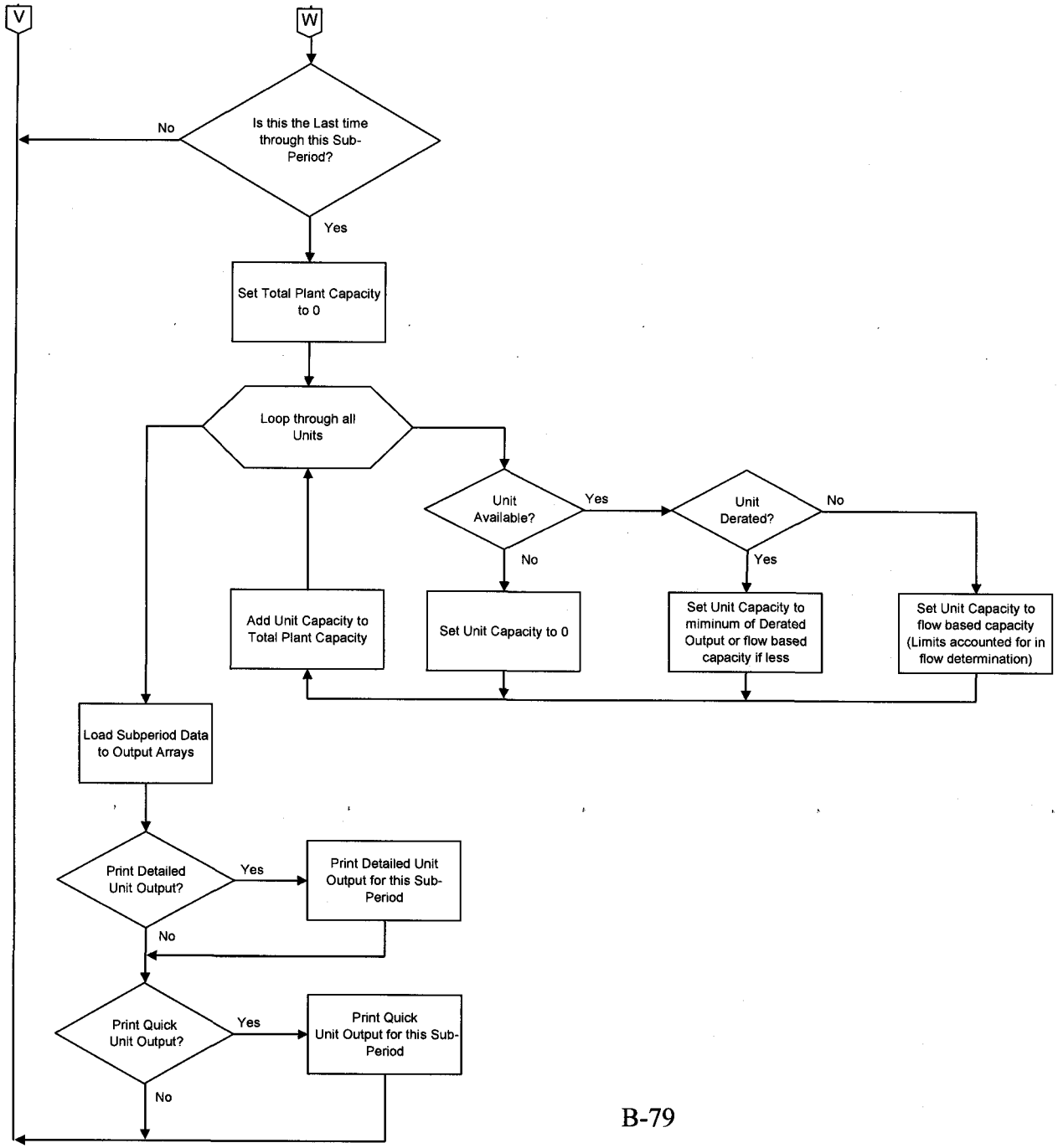


Figure B-3 – Detailed TEAM Logic Flow (continued)



[redacted]

Appendix D Cost estimate for S. Morgan Smith Units