**US Army Corps of Engineers**
**Walla Walla District**

# POWER SYSTEM ANALYSIS

## July 1999

## FOREWORD

This document is the product of the US Army Corps of Engineers' (Corps) efforts to involve the region in the development of the *Lower Snake River Juvenile Salmon Migration Feasibility Report/Environmental Impact Statement (FR/EIS)*. The Corps has reached out to regional stakeholders (states, tribes, Federal agencies, organizations, and individuals) for the input and development of various work products. This and various other products associated with the development of the EIS were authored and developed by these regional stakeholders and contractors. Although the Corps has acquired this document as part of its EIS process, the opinions and/or findings expressed herein do not necessarily reflect the official policy or position of the Corps. The Corps will review and incorporate information from these products into the analysis and development of the Draft FR/EIS.

In addition, this analysis is only one part of the overall Economic Appendix of the EIS. Other critical components of the economic analysis include recreation, regional, social, transportation, tribal, and water impacts. For a true economic analysis of the implications of any of the study alternatives, economic costs and benefits of all the components of the analysis must be considered, but without any individual component taken out of context.

This document is being released for **information purposes only**. The Corps will not be responding to comments at this time. The formal comment period will coincide with the release of the Draft FR/EIS, expected in Fall 1999.

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### 3.2.1. Introduction

The section summarizes the findings in the *Technical Report on Hydropower Costs and Benefits (Hydropower Technical Report)*. The purpose of this hydropower analysis was to identify the net economic costs associated with changes in hydropower production at the four Lower Snake River dams.

The scope of the hydropower impacts is large. Columbia River Basin hydropower projects serve as a major element in the Pacific Northwest (PNW) electrical industry, and provide about 60 percent of the total regional energy needs and 70 percent of the total electrical generating capacity in the region on an average basis. The nature of hydropower is that it is available in different amounts from year to year depending on streamflow conditions. In wet years, the amount of hydropower generation can be significantly greater than the average conditions, and this energy (commonly referred to as secondary) can serve as a major part of the export market outside of the PNW. In low water years, or high demand periods within a year, energy is often imported into the PNW to meet the power demands. Consequently, any changes in the generation of PNW hydropower could impact the amount of energy bought and sold, and the amount of new generating facilities to be built, throughout the entire West Coast of the United States. For these reasons, the scope of this analysis is the entire western United States and parts of Canada as defined by the Western Systems Coordinating Council (WSCC). The WSCC is a one of nine regional energy reliability councils that were formed due to a national concern regarding the reliability of interconnected bulk power systems. The WSCC comprises all or part of the 14 Western States and British Columbia, Canada, over 1.8 million square miles.

The hydropower study was conducted jointly by staffs of the Corps of Engineers and the regional power marketing agency, Bonneville Power Administration (BPA). As with other economic impact areas, an oversight group was formed to assist in the analysis and to provide a forum for interested parties to provide input. The Hydropower Impact Team (HIT) consisted of 10 to 20 members from numerous interested entities such as the Northwest Power Planning Council, the Bureau of Reclamation, National Marine Fisheries, regional tribes, river interest groups, and environmental groups. The HIT met regularly during the study to discuss appropriate approaches and assumptions to use in the analysis. The HIT also provided review and comments on drafts of the hydropower technical report.

The study process incorporated several elements to arrive at the estimate of economic effects associated with changes in hydropower with each of the alternatives. The process first considered how the impacted hydropower projects currently function, and used system hydro-regulation studies to estimate how much hydropower generation will occur with the different alternatives and different water conditions. This information was then incorporated into power system models to estimate how changes in hydropower generation will affect generation from other more costly power resources. The impacts of these changes on the market prices over time were also estimated. A wide range of key study assumptions was investigated and the uncertainties associated with these assumptions were examined. Sensitivity tests were performed on some of the major study assumptions to assure that results were reasonable from a wide range of viewpoints. The financial impact on regional ratepayers and possible mitigation for these impacts were also investigated. The power system modeling tools were used to help identify the changes in air pollutant emissions with the different alternatives.

### 3.2.2 Hydropower Characteristics

The hydropower projects of most interest to this study were the four Lower Snake River projects of Ice Harbor, Lower Monumental, Little Goose, and Lower Granite. However, almost all the hydropower projects in the Columbia-Snake system will be impacted under at least one of the alternatives being investigated. Table 1 describes some of the hydropower characteristics of each Lower Snake hydropower projects. Three of the Snake River projects are essentially identical in terms of hydropower facilities. The Ice Harbor project was constructed several years before the others and has less capacity. The overload capacity represents the maximum output that can be achieved. The average annual energy is presented in two different units: the average MW (aMW) which is the amount of generation averaged over all the hours of the year, and the annual MWh which is the sum of all generation over the entire year. This energy data was taken from the average of 60 historic water years for the base condition.

**Table 1**
**Hydropower Plant Characteristics**

| | Ice Harbor | Lower Monumental | Little Goose | Lower Granite | Lower Snake Total |
|---|---|---|---|---|---|
| Number Units | 6 | 6 | 6 | 6 | 24 |
| Capacity Per Unit (MW) | 3 (90)<br>3 (111) | 6 (135) | 6 (135) | 6 (135) | |
| Total Nameplate Capacity (MW) | 603 | 810 | 810 | 810 | 3,033 |
| Overload Capacity (MW) | 693 | 931 | 931 | 931 | 3,486 |
| In-Service Date | 1 (1961)<br>2 (1962)<br>3 (1975) | 2 (1969)<br>1 (1970)<br>3 (1979) | 3 (1970)<br>3 (1978) | 3 (1975)<br>3 (1978) | |
| Average Annual Energy (aMW), Base Condition | 264 | 332 | 317 | 333 | 1,246 |
| Average Annual Energy (1,000 MWh), Base Condition | 2,313 | 2,908 | 2,777 | 2,917 | 10,915 |
| Plant Factor Base Condition | 38% | 36% | 34% | 36% | 36% |

Figure 3 shows an estimate of the average monthly generation of the four Lower Snake River plants by month based on a system hydro-regulation model for the base condition (Alternative A1). The amount of generation from these plants can change significantly in different water years and seasons. The figure compares the monthly generation for a 60-year average simulation (from year 1929 to 1988), a low water year (1930-31), and a high water year (1955-56).

FIGURE 3 A1 Results - Monthly Generation - 4 Snake Riv Dams
Low WY (1930), High WY (1955-56) & 60 Year Average

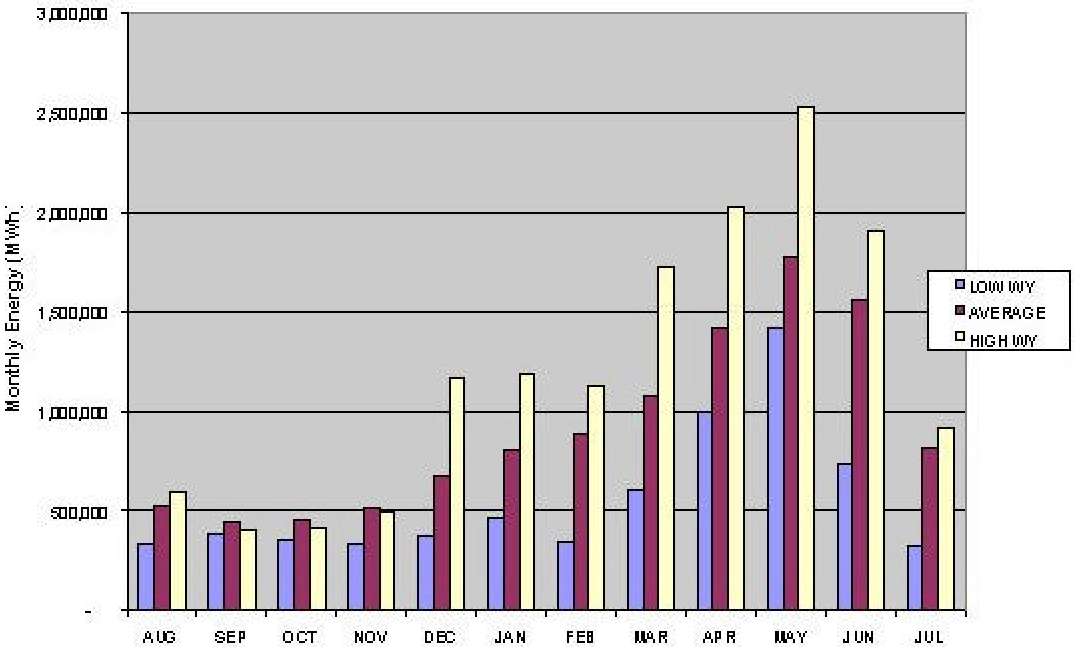
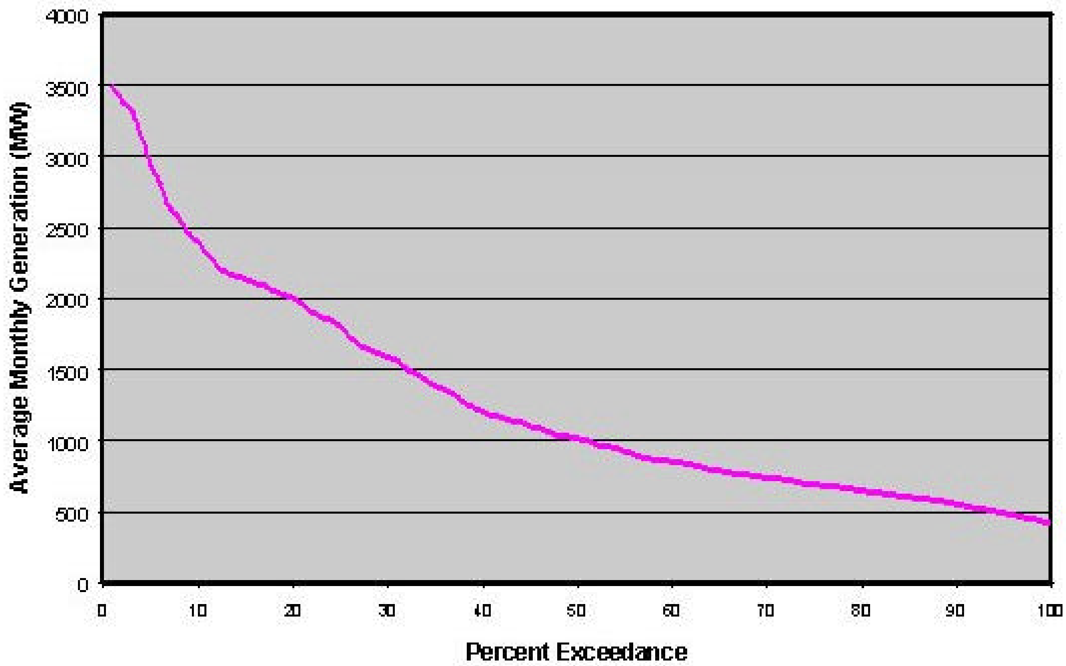



Figure 5 presents the monthly generation-duration curve based on the 60 water year conditions from 1928 to 1988, for the base condition. The generation in this figure is the combined monthly generation of the four Lower Snake River projects. This figure shows the percent of time in which average monthly generation equals or exceeds the generation in MW. For example, the monthly generation equals or exceeds 1,000 MW about 50 percent of the months of the 60 water years, and equals or exceeds 2000 MW about 20 percent of the time.

FIGURE 5 Lower Snake River Plants - Monthly Generation Duration




The hourly operation of the Lower Snake River plants is determined primarily by the amount of Snake River water arriving at Lower Granite because the four reservoirs have very limited storage capability and only minor tributary inflows into the reservoirs. The ability to store water over the week, month, or season cannot occur at these projects. The projects can somewhat shape the amount of generation throughout the day with the limited storage within the top 3 to 5 feet of operating range over the juvenile fish non-migrating periods of November through March.

### 3.2.3 Power System Characteristics

Table 3 demonstrates to what extent each power-generating source is used in the PNW. As can be seen in the table, hydropower makes up about 67 percent of the Pacific Northwest's total generating capacity, followed by coal. Next in terms of capacity available to meet demand is the import over the intertie system from regions outside of the PNW. The firm energy amount shown in this table reflects that which can be generated in the low water year of 1936-37. The year 1937 has been defined as the critical year for defining firm energy in many regional power planning studies. A distinction is often made between firm (also referred to as primary) energy and non-firm (referred to as secondary) energy in power markets because the firm energy can be counted on even in the most extreme historical low water years.

**Table 3**
**The Pacific Northwest Electric Generating Resources 1997[1]**

| Resource Type | Sustained Peak Capacity (MW)[2] | Percent of Total Capacity | Firm Energy[2] (aMW) | Percent of Firm Energy |
|---|---|---|---|---|
| Hydro | 25,887 | 67% | 12,187 | 57% |
| Coal | 4,521 | 12% | 4,061 | 19% |
| Nuclear | 1,162 | 3% | 841 | 4% |
| Imports | 2,996 | 8% | 1,669 | 8% |
| Combustion Turbines | 1,665 | 4% | 753 | 4% |
| Non-Utility Generation | 1,166 | 3% | 1,051 | 5% |
| Cogeneration | 775 | 2% | 675 | 3% |
| Other | 264 | 1% | 171 | 1% |
| **Total** | **38,436** | **100%** | **21,408** | **100%** |

[1]Source: BPA's *1997 Fast Facts*.
[2]For more information, see BPA's *Pacific Northwest Loads & Resources Study*.

Table 4 provides generation and capacity information for the entire WSCC, based on actual generation in 1997, rather than the firm energy. The most prominent source of generating capacity and energy in the WSCC is hydropower, but to a significantly less extent than in the PNW. Coal and natural gas driven thermal plants provide a much larger share of capacity and energy in the WSCC than in the PNW. However, hydropower makes up the vast majority of system capacity and generation in the PNW, and is the largest contributor for the entire WSCC.

**Table 4**
**Western Systems Coordinating Council (WSCC)**
**Electric Generating Resources, 1997**

| Resource Type | Capacity (MW) | Percent of Total Capacity | 1997 Energy (aMW) | Percent of Total Energy |
|---|---|---|---|---|
| Hydro-Conventional | 61,043 | 39% | 33,367 | 39% |
| Hydro-Pump Storage | 4,316 | 3% | 533 | 1% |
| Steam - Coal | 36,325 | 23% | 28,378 | 33% |
| Steam - Oil | 746 | 0% | 239 | 0% |
| Steam - Gas | 23,241 | 15% | 5,018 | 6% |
| Nuclear | 9,258 | 6% | 7,472 | 9% |
| Combustion Turbine | 5,846 | 4% | 206 | 0% |
| Combined Cycle | 3,777 | 2% | 779 | 1% |
| Geothermal | 3,060 | 2% | 2,270 | 3% |
| Internal Combustion | 293 | 0% | -- | 0% |
| Cogeneration | 8,119 | 5% | 5,954 | 7% |
| Other | 1,891 | 1% | 1,317 | 2% |
| Pump-Storage Pumping | | | (445) | -1% |
| **Total** | **157,915** | **100%** | **85,089** | **100%** |

Source: 1998 WSCC Information Summary

### 3.2.4 Hydro-Regulation Models

The first step in defining the power impacts was to identify the amount of hydropower generation with each alternative. The second step was to identify the economic effects of changes in the hydropower.

The study utilized two system hydro-regulation models to perform the first step. The system hydro-regulation models simulate the operation of hydropower plants with each alternative with historical water conditions encountered over 50 or 60 water years, depending on which model is used. The models were used to define the power impacts at each hydropower plant in the Pacific Northwest with the alternative operations of the system. The model used by the Corps was the Hydro System Seasonal Regulation Program (HYSSR) and the BPA model was the Hydro Simulator Program (HYDROSIM, sometimes labeled HYDSIM). The major output of either model was a month-by-month hydropower generation amount from each hydropower plant in the Columbia Basin, for each of the years simulated by the models. See Appendix ____, Hydrology and Hydro-Regulations, of the Lower Snake River Juvenile Mitigation Feasibility Study for detailed description of the hydro-regulation models.

Table 6 summarizes the total monthly PNW system generation amounts for each of the alternatives as compared to the base case condition, Alternative A1. This table provides the monthly averages over all the water year simulations done by the HYSSR (60 years) and HYDROSIM (50 years). The table shows the total hydropower production in the PNW (System Generation). The HYSSR and HYDROSIM models have slightly different definitions of which hydropower projects are included in the PNW system generation, and hence the total system generation amounts are slightly different. These differences in system-wide hydropower generation estimates are used later in this analysis to define the economic effects of each alternative. However, the most important element of this study is the change in generation from the base condition, and the last section of this table shows how the difference between the two models. The last set of numbers in the table shows differences between the two hydro-regulation models are relatively small, on average, but can be significant for specific months and alternatives.

**Table 6**
**Hydropower Analysis**
**HYSSR & HYDROSIM Results by Alternative**
**System Generation (aMW)**

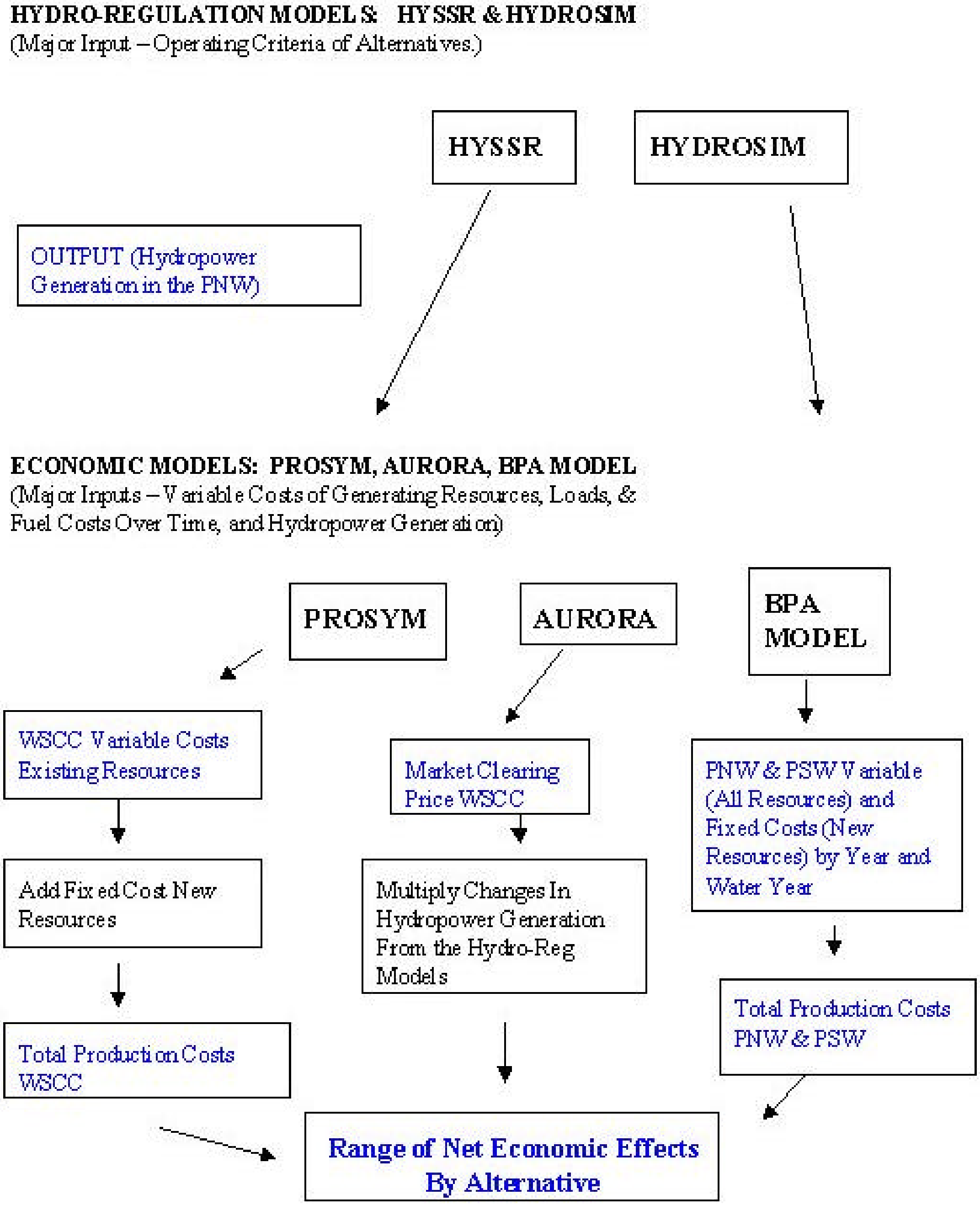
| Alternatives | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Ann Avg | % of A1 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **HYSSR Results: Average Generation Over 60 Water-Year Simulations** | | | | | | | | | | | | | | |
| A1 | 9,466 | 9,520 | 10,414 | 14,071 | 16,800 | 15,200 | 13,820 | 15,846 | 18,729 | 18,834 | 13,725 | 11,997 | 14,038 | |
| A2 | 9,467 | 9,533 | 10,418 | 14,078 | 16,803 | 15,203 | 13,820 | 16,006 | 19,049 | 19,139 | 13,743 | 12,008 | 14,108 | |
| A3 | 9,046 | 8,953 | 10,021 | 12,867 | 15,987 | 14,098 | 11,794 | 13,437 | 16,314 | 16,703 | 12,728 | 11,280 | 12,771 | |
| A5 | 9,317 | 9,107 | 10,494 | 13,253 | 16,230 | 14,247 | 11,796 | 13,261 | 16,078 | 16,538 | 12,450 | 10,851 | 12,805 | |
| A6a | 9,495 | 9,535 | 10,401 | 14,084 | 16,861 | 15,128 | 13,802 | 16,016 | 18,545 | 18,879 | 13,817 | 12,182 | 14,064 | |
| A6b | 9,412 | 9,504 | 10,437 | 14,042 | 16,840 | 15,088 | 13,819 | 16,081 | 18,578 | 18,755 | 13,731 | 12,011 | 14,028 | |
| **SYSTEM IMPACTS HYSSR (Generation Difference From A1; Negative Means Loss in Energy From A1)** | | | | | | | | | | | | | | |
| A2 | 1 | 13 | 4 | 7 | 3 | 3 | 0 | 160 | 320 | 18 | 11 | 70 | 0.5% | |
| A3 | -420 | -567 | -393 | -1,204 | -813 | -1,102 | -2,026 | -2,409 | -2,415 | -997 | -717 | -1,267 | -9.0% | |
| A5 | -149 | -413 | 80 | -818 | -570 | -953 | -2,024 | -2,585 | -2,651 | -1,275 | -1,146 | -1,233 | -8.8% | |
| A6a | 29 | 15 | -13 | 13 | 61 | -72 | -18 | 170 | -184 | 92 | 185 | 26 | 0.2% | |
| A6b | -54 | -16 | 23 | -29 | 40 | -112 | -1 | 235 | -151 | 6 | 14 | -10 | -0.1% | |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **HYDROSIM Results: Average Generation Over 50 Water-Year Simulations** | | | | | | | | | | | | | | |
| A1 | 10,572 | 11,558 | 12,735 | 15,935 | 19,669 | 16,435 | 14,858 | 17,777 | 20,487 | 19,960 | 15,333 | 13,108 | 15,702 | |
| A2 | 10,572 | 11,558 | 12,735 | 15,935 | 19,671 | 16,435 | 14,858 | 17,927 | 20,732 | 20,202 | 15,343 | 13,108 | 15,756 | |
| A3 | 10,183 | 10,865 | 12,244 | 15,031 | 18,677 | 15,324 | 13,057 | 15,676 | 18,168 | 17,923 | 14,220 | 12,352 | 14,477 | |
| A5 | 10,596 | 11,200 | 12,421 | 15,492 | 19,328 | 15,469 | 13,042 | 15,436 | 17,906 | 17,776 | 13,694 | 11,837 | 14,516 | |
| A6a | 10,503 | 11,562 | 12,752 | 15,940 | 19,684 | 16,466 | 14,830 | 17,708 | 20,544 | 20,137 | 15,405 | 13,622 | 15,763 | |
| A6b | 10,518 | 11,637 | 12,787 | 16,037 | 19,708 | 16,468 | 14,890 | 17,745 | 20,453 | 19,888 | 15,285 | 13,009 | 15,702 | |
| **SYSTEM IMPACTS HYDROSIM (Generation Difference From A1; Negative Means Loss in Energy From A1)** | | | | | | | | | | | | | | |
| A2 | 0 | 0 | 0 | 0 | 2 | -1 | 0 | 150 | 245 | 241 | 11 | 0 | 54 | 0.3% |
| A3 | -389 | -693 | -491 | -904 | -992 | -1,111 | -1,801 | -2,101 | -2,319 | -2,037 | -1,112 | -755 | -1,225 | -7.8% |
| A5 | 24 | -358 | -315 | -444 | -341 | -967 | -1,816 | -2,340 | -2,581 | -2,185 | -1,639 | -1,271 | -1,186 | -7.6% |
| A6a | -69 | 5 | 16 | 5 | 14 | 30 | -28 | -68 | 57 | 177 | 72 | 514 | 61 | 0.4% |
| A6b | -54 | 79 | 52 | 102 | 38 | 33 | 32 | -31 | -34 | -72 | -47 | -99 | 0 | 0.0% |
| **Differences in Impacts Between HYSSR and HYDROSIM (Negative Means HYSSR Difference is Larger)** | | | | | | | | | | | | | | |
| A2 | -1 | -13 | -4 | -7 | -1 | -4 | 0 | -10 | -75 | -64 | -7 | -11 | -16 | -0.1% |
| A3 | 31 | -126 | -98 | 300 | -179 | -9 | 225 | 308 | 96 | 94 | -115 | -38 | 42 | 0.3% |
| A5 | 173 | 55 | -395 | 375 | 229 | -14 | 208 | 245 | 70 | 111 | -364 | -125 | 47 | 0.3% |
| A6a | -99 | -11 | 29 | -8 | -46 | 102 | -9 | -238 | 241 | 131 | -19 | 329 | 34 | 0.2% |
| A6b | 0 | 95 | 29 | 131 | -2 | 145 | 33 | -266 | 117 | 7 | -53 | -112 | 10 | 0.1% |

### 3.2.5 Power System Models

The study team used several models in the analysis. Figure 9 provides a schematic of how the several models were integrated to estimate the range of net economic effects. Specifics of each model are provided in the technical report. In general, the results from the hydro-regulation models were fed into the economic models. Each economic model provided somewhat different outputs, so additional analysis was added to model results to define the net economic effects.

FIGURE 9 SCHEMATIC OF MODELS USED IN HYDROPOWER ANALYSIS



Because of the inter-related, market driven nature of the electric industry, it was decided that the evaluation of changes in hydropower production in the PNW must be evaluated on a system-wide basis. This study uses two separate system production cost models, one by the Corps and one by BPA, to evaluate the net economic effects of changing power generation at the four Lower Snake Dams and John Day. A third approach developed by the Northwest Power Planning Council (NPPC) was also utilized in this study.

These multiple approaches were undertaken to look at the impacts from different analytical viewpoints to assure that the economic effects are adequately bracketed in the final estimates. The study progressed by examining model results for each alternative with the different system approaches. To the extent possible the basic input assumptions were standardized among the models, and these assumptions are discussed below. Upon comparing results, the study team built a consensus on the best analytical approach.

The evaluation of the net economic effects on hydropower was based on two basic approaches: a market price analysis and a system production cost analysis. The AURORA model served as the basic tool for the market price analysis, and the PROSYM and BPA models were used for the system production costs analysis. It is important to note that the market price and system production cost approaches are intended to measure the same net economic effects, and hence are directly comparable.

Many similarities do exist in the three power system models used in this analysis. They are all designed to identify how the different power generating resources will be operated to meet projected power loads (demand). They do vary in scope from hourly models (Aurora and PROSYM) to a monthly model that stratifies hours in the month into different blocks of peak and non-peak hours. The geographic regions covered by each model are different. The treatment of constructing new power resources and retiring power plants varies among the models. The primary outputs of each model are different. The Aurora model identifies the marginal cost in each period and this is assumed to be the market-clearing price. PROSYM provides the production costs (variable costs) to meet loads by all regions in the WSCC. The BPA model also identifies production costs but also provides the fixed costs of new resources to arrive at the total system production costs.

**3.2.5.1 Market Price Model.** The conceptual basis for evaluating the benefits from energy produced by hydropower plants is society's willingness to pay for the outputs, which sometimes can be obtained through market prices. With the movement towards a more competitive market, the price of electricity in the California market and elsewhere is being priced at or near the marginal production cost of the last resource to provide the needed electricity. So, this part of the power analysis looked at valuing the incremental changes of hydropower generation at the market price, which was based on the marginal cost of the last resource used to meet load in the specific timeframe.

As more competitive electricity markets develop, prices will not be set to average costs as they have been in the past. Rather, the various services provided--operating reserves, voltage stabilization, *etc.*--will be available and priced separately. However, consumers will not have to purchase all of these services from separate suppliers. During most time periods in the power spot market, the generation price of electricity will be set by the operating costs of the most expensive generating unit needed to meet demand, or what is referred to in economics as the "marginal cost" of production. In general, a supplier will not be willing to sell power below the market price of the most expensive facility operating at a given time, because consumers will be willing to pay the higher price. Similarly, consumers will be unwilling to pay more than the cost of the most expensive operating available generator, since other suppliers will be offering lower prices. With prices set to marginal costs, the market will clear: all suppliers willing to provide power and all consumers willing to purchase power at the market price will be doing so.

Market prices were obtained from the NPPC study (NPPC JUNE 1998) entitled *Analysis of the Bonneville Power Administration's Potential Future Costs and Revenues, 5 June 1998.* The market prices used in this study were developed with a model called Aurora, developed by a private firm, EPIS, Inc. The general elements of the Aurora model are provided here, and a more thorough description of Aurora is contained in Hydropower Technical Report. One of the principle functions of Aurora is to estimate the hourly market-clearing price at various locations within the WSCC.

Aurora estimates prices by using hourly demands and individual resource operating characteristics in a transmission-constrained chronological dispatch algorithm. The operation of resources within the WSCC is modeled to determine which resources are on the margin for each area in any given hour.

In Aurora, the WSCC is broken into 12 geographic areas largely defined by states, with the exception of California, which is split into a northern and southern area, and Oregon and Washington, which are combined into one area. Long term average demand and hourly demand shapes for these regions are input. These demand regions are connected by transmission links with specified transfer capabilities, losses and wheeling costs.

Existing generating units, approximately 2000 of them in the WSCC, are defined and modeled individually with specification of a number of cost components and physical characteristics and operating constraints. Hydro generation for each area, with instantaneous maximums, off peak minimums, and sustained peaking constraints are also input. Demand side resources and price induced curtailment functions are defined, allowing the model to balance use of generation against customer demand reduction alternatives.

Aurora uses this information to build a least cost dispatch for the WSCC. Units are dispatched according to variable cost, subject to non-cycling and minimum run constraints until hourly demand is met in each area. Transmission constraints, losses, wheeling costs and unit start-up costs are reflected in the dispatch. The market-clearing price is then determined by observing the cost of meeting an incremental increase in demand in each area. All operating units in an area receive the hourly market clearing price for the power they generate.

The hourly market clearing prices are developed on an area-specific basis. The analysis for this report uses the Oregon/Washington area price to value PNW generation. This price can be interpreted as the average busbar price as seen by generation in the OR/WA area. Charges for delivery within the OR/WA area are not included in the price.

Aurora also has the capability to simulate the addition of new generation resources and the economic retirement of existing units. New units are chosen from a set of available supply alternatives with technology and cost characteristics that can be specified through time. New resources will only be built when the combination of hourly prices and frequency of operation for a resource generate enough revenue to make construction profitable (*i.e.*, the ability of investors to recover fixed and variable costs with an acceptable return on investment).

Aurora uses an iterative technique in these long-term planning studies to solve the interdependencies between prices and changes in resource schedules. This effectively results in construction and retirement decisions being based on "perfect knowledge" of future prices.

Existing units that can't generate enough revenue to cover their variable and fixed operating costs over time are identified and become candidates for economic retirement. To reflect the timing of transition to competition across all areas of the WSCC, the rate at which existing units can be retired for economic reasons is constrained in these studies.

**3.2.5.2 System Production Cost Models.** The other approach to define net economic effects was a system production cost analysis. The economic effects were identified by comparing system production costs with the level of hydropower production from the different alternatives being investigated. Changes in hydropower generation result in different levels of operation of more costly thermal generating power plants. Hence, the economic values of different increments of hydropower energy were defined by the displacement of thermal resource generation.

For this analysis, the total system production costs are defined as the sum of the variable operating costs (production costs) and the fixed costs (annualized capital costs) of new resources added to meet loads. The total system is defined by different geographic regions in each model. However the basic definition is:

| | | |
|---|---|---|
| **Total System Production Costs =** | **Variable Costs** | **+ Fixed Costs** |
| | (Production) | (New Capacity) |

Both BPA and the Corps have models that estimate the costs of meeting energy demand (loads) with available hydropower energy and thermal resources. The models identify the most cost-effective way to meet loads given all system constraints. These models estimate which resources will be operated to meet loads and the variable costs of these resources are summed to define variable production costs. Loads may also be met through purchase of energy from the PNW, PSW, or other regions. The purchase price reflects the variable generation costs and the transmission costs of the resource used to provide the energy. Production costs in the PNW and PSW will vary depending on how much Columbia River hydropower is generated. The output of hydro-regulation models (HYSSR and HYDROSIM) served as the major input to the system energy production cost models.

Table 7 provides a description of the major concepts of the BPA model. The model categorizes West Coast thermal resources into several production cost blocks based on the average efficiencies of the plants. The more inefficient plants tend to be the older plants that are operated last in the dispatch order. The BPA model compares the PNW and PSW loads to the monthly hydropower and thermal generation for each simulation year. As hydropower generation varies, the thermal generation amounts and costs change. The model identifies the marginal costs of the resources which hydropower will displace. The load is broken into three distinct periods of each week or month. These periods are the super peak (hours 7 a.m. to 10 a.m. and 5 p.m. to 8 p.m. each weekday), peak (hours 6 a.m. to 10 p.m. Monday through Saturday, not including the super peak hours) and non-peak hours (the remainder of the week). This stratification accounts for the significant variations in prices and resources used to meet loads in these different periods of the week.

**Table 7**

**Model Philosophy and Use**

- Underlying philosophy is that the future value of electricity in the PNW will be determined by the cost of operating the next available West Coast resource--either operation of existing resources or construction and operation of new resources.
- Model has a PNW and a PSW region. Canada and the Inland SW are not modeled.
- Model attempts to meet West Coast loads with West Coast resources. Each region's resources are used to meet its own loads. If the PNW has surplus resources, they are available for sale to the PSW. If the PNW is deficit, PSW resources are available for purchase (both transactions subject to intertie limits).
- Model calculates results on a monthly basis, but is also capable of dividing the month into super peak, peak and non-peak hours. Currently, super peak hours consist of 30 hours per week, peak hours consist of 66 hours per week, and non-peak hours consist of 72 hours per week.
- Results consist of the total cost for operating the West Coast regional electric system. Total costs include variable costs of all resources and the fixed costs for any new resources. Other outputs consist of the marginal cost for meeting an increment of PNW load, PNW load/resource balances, operation of specific resource blocks, and many other outputs.

**Existing System**

- The PNW region consists of information on PNW loads and resources. PNW resources are divided into six groups: non-displaceable (nuclear, renewables, *etc.*); low cost coal (mostly east-side coal plants); high cost coal, existing single cycle combustion turbines (CTs), existing combined cycle combustion turbines (CCs) and imports.
- The PSW region consists of information on PSW loads and resources. PSW resources are grouped into two categories: displaceable and non-displaceable. Further, displaceable PSW resources are defined by their heat rates. A supply curve of PSW resources by heat rate is developed in the model.
- Data for both regions consist of existing loads, existing resources, variable cost of operating existing displaceable resources, current and future gas prices.
- Data for the PNW includes monthly hydro generation based on 50 historical water years.
- Data for both regions includes the cost for failing to meet native loads (cost of unserved load).

**New Resources**

- The model has a limited optimization routine based on the following philosophy: new resources will be built when they are less expensive to build and operate than the combination of the cost of operating existing resources and curtailing load, when no other resources are available. Existing resources consist of both supply and demand side resources. The only future resource choice is new combined cycle combustion turbines (CCs).

**Operations**

- Model operates from a PNW perspective. Model checks whether or not PNW is surplus or deficit given operation of all existing and new resources. If surplus, dispatch logic (hardwired in model) is as follows:
  Displace all PNW existing CT resources.
  Displace all PNW high cost coal resources.
  Sell to PSW (given intertie and market limits).
  Displace all PNW existing CC resources.
  Displace all PNW new CC resources.
  Displace all PNW low cost coal resources.
  Displace imports.

  If deficit, model buys from the PSW (given intertie limits and PSW resource availability). If no PSW resources available, model purchases available demand side resources, and then curtails PNW load.

**Uncertainties**

- Model handles uncertainty in PNW hydro by modeling 50 years of historic hydro information.
- Model has three different load forecasts for the PNW and PSW--low, medium and high.
- Model has three different gas price forecasts for the PNW and PSW--low, medium and high.

The Corps utilized an existing proprietary hourly system production model entitled PROSYM, which has been used extensively by the Corps throughout the United States. PROSYM was developed and is maintained by Henwood Energy Services of Sacramento, California. The Corps of Engineers (CENPW-NP-ET-WP) used the model under a contract with Henwood. The Corps has utilized this model, and its TVA-developed predecessor, for a number of years. Table 8 provides a description of the major concepts of the model. The PROSYM model has an extensive database, which includes operating characteristics of all WSCC power plants, current fuel prices, plant efficiencies, and inter-regional marketing conditions. The model dispatches thermal and hydropower resources on an hourly basis to meet energy demand. Hydropower resources are based on weekly energy amounts generated by the hydropower regulator models from the projects in the study region, or weekly energy amounts input to the model. This model was used to examine in great detail selected water years. The model also includes a pollution emissions subroutine.

**Table 8**
**Corps of Engineer's Use of PROSYM Model**

**Model Philosophy**
- Simulates a power system operation on a chronological hourly basis.
- Simulates a year hour-by-hour, in one-week increments.
- Used to define power system operating costs (variable costs of operating resources) to meet loads.
- Operating costs for each plant include fuel costs, variable operation and maintenance costs, and startup costs.
- Meets hourly loads in the most economic manner possible given a specified set of generating resources.
- Recognizes operating constraints imposed on individual units.

**Existing System Simulation**
- Uses external data (like HYSSR output) to define hydropower week-by-week generation.
- Data utilized for thermal plants include: unit capacity, fuel type, number of units per plant, ramp rate, fuel cost, minimum and maximum unit output, minimum down time, variable heat rate, forced outage rate, minimum up time, start-up costs, maintenance schedule, on-line date, retirement date, categorization by type such as base load, intermediate, or peaking.
- Dispatched in order of increasing energy costs, unless fuel supply contracts or other factors require a specific dispatch.
- After units are dispatched, a probability distribution is used to develop forced outages, and contingent resources are then dispatched.
- Hydropower inputs required: (Can define numerous types of hydropower units)
    - Required minimum continuous output
    - Normal maximum output
    - Energy output for each week
    - Peaking output
    - Pump storage characteristics
- Multi-area capability allows for bi-directional line limits, transmission losses, and wheeling charges. Unit commitment and dispatch is fully "transmission-network aware."
- Can incorporate area-level operating reserve requirements.
- Calculates the marginal cost data for each transmission area.

**New Resources**
- User specifies new resources to meet load if existing resources are inadequate.
- Planned resources can be modeled to come online at specified dates in the future.

**Operation**
- Uses extensive Regional Databases developed from unrestricted sources such as FERC filings, NERC reliability councils, state regulatory and planning commissions, *etc*.
- Output is production costs by resource to meet weekly load.
- Output available by regions, by plants, and by plant types.
- Includes a pollution emission subroutine that estimates emissions with each scenario.

**3.2.5.3 Model Inputs.** This section describes the major inputs utilized by the system production cost models and the market price analysis. Most of these key model assumptions were taken from the NPPC's report *Analysis of the Bonneville Power Administration's Potential Future Costs and Revenues, 5 June 1998.* A range of projections (low, medium, and high) was made for each key variable to account for the uncertainty associated with predicting future conditions.

**System Loads.** The system loads, or power demands, are shown in Table 9 for the starting year of 1997, by each of the 12 Aurora demand regions.

**Table 9**
**Aurora Model**
**1997 Electric Loads by Demand Region**

| Region | Load (aMW) |
|---|---|
| OR/WA | 16779 |
| North CA | 10730 |
| South CA | 16783 |
| Canada | 11842 |
| ID | 2644 |
| MT | 1554 |
| WY | 1455 |
| CO | 4681 |
| NM | 2106 |
| AZ | 6474 |
| UT | 2481 |
| NV | 2817 |
| **Total** | **80346** |

Source: NPPC's study, *Analysis of the Bonneville Power Administration's Potential Future Costs and Revenues, 5 June 1998*

Demand was assumed to grow at equal rates in all of the demand areas. Although this will certainly not be the case, the team did not research every state’s demand forecasts because these were likely to include a wide range of basic demographic assumptions. It was also felt that historical relative growth rates for states might not be a good indicator of future demand growth.

For the medium case, demand was assumed to grow at 1.5 percent annually. In the low case, the assumption was 0.5 percent per year, and in the high case it was 2.5 percent. The load forecasts project the PNW demand in terms of average megawatts by year up to year 2020.

**Fuel Prices.** The major component of production cost of any power system is the costs of fuels expended to generate the electricity. Hence, the fuel prices assumed to occur over time are a critical element of the system production cost modeling and the market price analysis. This section describes the assumptions made for the fuel prices in the different regions of the WSCC.

**Natural Gas Prices.** The NPPC Aurora model is currently structured to develop its natural gas price assumptions based on two pricing points, Henry Hub in Louisiana and Permian in Texas. Prices in the Aurora regions are then based on a series of differentials from these trading hubs. The results of making the differential adjustments are shown in Table 10. This table shows the assumed natural gas prices on a $/million BTU basis for 1997.

**Table 10**
**Assumed 1997 Natural Gas Prices by Region**

| Region | Sub-Region | Estimated Start Price |
|---|---|---|
| CA Border | | $1.90 |
| | Southern CA | $2.15 |
| AZ | | $2.10 |
| NM | | $1.95 |
| NV | | $2.00 |

The final assumption for natural gas prices was the real escalation rate applied to the gas prices. Three different future economic scenarios were projected. For the medium economic forecast case, it was assumed the medium gas price escalation included in the Council's power plan, 0.8 percent per year escalation above general inflation. The low forecast assumed a -1.0% real escalation rate, while the high projection assumed +2.0% real escalation. These assumptions translate into similar growth rate in all regions with one exception. In 1999 and 2000 significant expansions to pipeline capacity to export from Alberta to the East are expected to come online. This expanded export capacity will have the effect of increasing prices in Alberta and British Columbia, perhaps significantly. To reflect this it was assumed that the basic differential from Canadian markets to Henry Hub decreases in the medium case. The Alberta Energy Company (AECO) Hub price in Alberta decreases from $ -.65 to $ -.45 by the year 2001. The Sumas differential decreases from $ -.55 to $ -.40 during the same period. These differential decreases result in significant increases to Northwest natural gas prices in the early years of the analysis. A range of natural gas assumptions is explored in the analysis as presented Table 12.

**Table 12**
**Summary of Natural Gas Price Assumptions**

| 1997 Price | Low | Medium | High |
|---|---|---|---|
| Henry Hub | $1.80 | $2.00 | $2.25 |
| Permian | $1.60 | $1.80 | $2.15 |
| Basis Differential | | | |
| AECO<br>Sumas | -.65 constant<br>-.55 constant | -.65 down to -.45<br>-.55 down to -.40 | -.65 down to -.20<br>-.55 down to -.10 |
| Escalation Rates | -1.0% | +0.8% | +2.0+ |

**Oil Prices.** For the base year of 1997 it was decided to use the starting crude oil prices at $3.50 per MMBtu with a low real escalation rate of 0.5 percent per year. This escalation rate was applied to all oil fuels. The 1997 starting values that were selected for other oil fuels are shown in Table 13.

**Table 13**
**Fuel Oil 1997 Prices Used in Analysis**

| Fuel Oil Type | 1997 Price ($/MMBtu) |
|---|---|
| Crude Oil | $3.00 |
| #1 Fuel Oil | $5.00 |
| #2 Fuel Oil | $4.50 |
| #3 Fuel Oil | $4.25 |
| #4 Fuel Oil | $3.85 |
| #5 Fuel Oil | $3.50 |
| #6 Fuel Oil | $2.70 |

Because oil prices do not appear to play an important role in determining the future market price of electricity, oil prices ranges were not used in the analysis.

**Coal Prices.** The other fuel, besides natural gas, that plays a significant role in the market price of electricity is coal. It was assumed that coal prices would decline in real terms in the base and low cases and to remain constant in the high case. In the low case coal prices were assumed to decline by 2 percent a year. In the base case, they decline at 1 percent a year. These growth rates were based on the Energy Information Administration's *Annual Energy Outlook*.

**Resources; Existing and Future.** To meet load growth over time it was necessary to project what kind of resources will be built in the future, and under what conditions these will be built. Each of the three models used in this analysis approached the addition of new thermal resources in different manners as discussed in section 3.2.6. The type of resources to be added to the system was reviewed by the study team. It was found that the most predominate type of fuel plant that has been recently added to power systems on the West Coast have been natural gas-fired combined-cycle combustion turbine (CC) plants. It was found that CC natural gas plants represented the most cost-effective new additions over a wide range of potential plant factors. It was assumed in the Corps and BPA models that all new thermal resources to be built through year 2017 would be natural gas-fired combined cycle power plants.

The NPPC as part of its Power Plan responsibilities keeps abreast of the latest construction and operating costs for all potential resources. The construction costs identified for CC plants of 250 MW capacity in the West Coast region were estimated to be $601per kW of installed capacity, at the 1998 price level. The average heat rate of the new CC plants in 1998 was assumed to be 7,045 Btu/kWh. This heat rate was assumed to go down over time at the rate of change described in the next section. The construction costs were based on the most recent financing experienced by the industry. The Corps of Engineers evaluates capacity costs based on procedures that were developed by the Federal Energy Regulatory Commission (FERC). These procedures identify the construction costs of different resources based on the current Federal discount rate (6.875%) and specific assumptions about taxes and insurance. Using the FERC process the plant construction costs of a 150 MW CC plant was $622/kW, and the costs of a 225 MW CC plant was $615/kW. The FERC database did not include costs for a 250 MW CC plant, but it can be assumed that construction costs would be somewhat less than the $615/kW costs and probably will approach the $601 costs identified by the NPPC. So, for all practical purposes these different construction costs (with different financing assumptions) are sufficiently close to ignore any differences. For this reason, all CC construction costs were assumed to be $601/kW. To include these costs in the annual simulations, the construction costs were adjusted to an annual fixed cost amount. The fixed costs used in the BPA model were in the 11.4 to 11.9 mills/kWh range, depending on the year of simulation. For comparison purposes the annualized values of the construction and fixed O&M costs for gas powered combined-cycle powerplants, computed from a model developed by FERC, were used only in the PROSYM studies. The annualized value used in the PROSYM study was $86/kW-yr delivered to the distribution system.

**Combustion Turbine Costs and Technology.** Because new capacity additions are comprised of natural gas-fired combined-cycle (CC) power plants, an effort was made to develop plausible and consistent assumptions regarding the evolution of the cost and performance of these plants over the study period.

Continuing advances in aerospace gas turbine applications are expected to lead to further reduction in the cost and increases in the efficiency of power generation equipment. For this study, cost reduction assumptions are based on projected improvement in gas turbine specific power.[1] Increases in specific power produce greater output with no increase in physical size, thereby reducing cost. Historical rates of improvement and estimated ultimately achievable rates of specific power suggest that over the study period specific power will continue to improve, on average, at constant rates. The resulting projections of annual cost reduction averaged - 0.6 percent in the Medium forecast, -1.2 percent in the Low and - 0.1 percent in the High forecast. These reductions were applied to both capital and operating costs of new CC plants.

**Unserved Load.** In each of the three models, not all load was met in each time period. The amount of load to be met by the available resources is a fixed input to each of the models. The models then identify the most cost-effective way to meet that load given the resources available to the model. System simulations are run with the different water years, and the amount of available energy to serve load can vary substantially with the different water years. Since the models were trying to meet load in every hour, or block of hours, there were instances in which not enough energy or capacity was available to meet each hourly demand.

Different approaches were taken to account for the economic costs of the unserved load. In the real world, if shortages like this occur, the system will start shedding loads by not meeting certain loads, and curtailing the amount of energy provided in a particular time frame to some or all electric customers. There will clearly be an economic cost associated with this curtailment. One approach considered for this study was to simply assign a relatively high cost for every shortfall in satisfying the load. This high value was assumed to represent a proxy for the economic cost of curtailment. Another approach used was to recognize that demand-side management measures could be instituted to reduce peak load during these critical hours.

Although it is likely that the market will come up with innovative approaches to reducing peak demands in response to time of use pricing, it was assumed that the market could achieve up to 26 percent as the maximum peak reduction through demand side voluntary actions.

The NPPC developed a supply curve for demand-side resources based on the best available information. The supply curve used in the Aurora model is presented in Table 15.

**Table 15**
**Demand-Side Supply Curve**

| Step | Share of Potential | Mills/KWh |
|---|---|---:|
| Step 1 | First 20% | 50 |
| Step 2 | Second 20% | 100 |
| Step 3 | Third 20% | 150 |
| Step 4 | Fourth 20% | 250 |
| Step 5 | Last 20% | 500 |
| Step 6 | Unserved Peak | 1000 |

### 3.2.6 Net Economic Effects By Alternative

As described above, two different approaches were undertaken to estimate the net economic effects associated with changes in hydropower production in the PNW - system production costs and market pricing.

**3.2.6.1 System Production Costs Analysis.** The economic effects provided in this section are based on the system production costs as defined by the two production cost models. A range of results is presented based on three assumptions of the key variables of fuel costs and loads. The future condition hereafter referred to as Low, combines the lowest estimate of fuel prices, the most rapid advancement in generation technology, and the low estimate of future load growth for all regions in the WSCC. Likewise, the Medium conditions combined the medium projections of fuel price, technology advancement, and load. The High condition combined the high projections of these three parameters.

Many of the tables in this section provide the description of total system production costs for each alternative as estimated by the BPA model and the PROSYM model. As can be seen from these tables, the BPA model was run over a much broader range of assumed conditions. This is a spreadsheet model, which has considerable flexibility. The PROSYM model is a much more complex hourly model, and time constraints did not allow for running this model for the full range of potential future conditions. Another major difference in the two models is that the BPA model was run for each of the 50 historic water years, while the PROSYM model was only run for an average water year based on the average of all 60 water years simulated by the HYSSR model. The scope of the BPA model is the PNW and California, while the PROSYM model includes all of the WSCC region.

The terminology used here refers to variable and fixed costs, and this is similar to the energy and capacity costs used in other studies. Energy is defined as that which is capable of doing work, and is measured over a time period. Electrical energy is usually measure in kilowatt-hours (kWh), megawatt-hours (MWh) or average MW (aMW - the average of MW produced over the entire year of 8,760 hours). Capacity is the maximum amount of power that a generating plant can deliver, usually expressed in kilowatts or megawatts. In the system production costs the variable costs are the costs associated with meeting energy requirements and they go up and down, as energy is needed to meet demand. The fixed costs are the costs needed to provide new capacity and this does not vary with hourly production. The fixed costs represent the annualized value of constructing the new capacity.

**Variable Production Costs.** The variable costs include the fuel costs and the variable operating costs of the many different thermal plants. If energy is transmitted between market regions, the cost associated with this transmission is also included in the variable production costs. Table 16 provides a summary of the variable production costs by generating resources as estimated by the BPA model for one specific year (2010), the medium forecast condition, the average of 50 water years, and the two alternatives of A1 and A3. Table 17 provides the same type of information from the PROSYM model. These are provided as samples to demonstrate the nature of the estimated production costs for the PNW and California in the BPA model and the entire WSCC in the PROSYM model. Similar results were computed for all the future years of 2002 to 2017, for the low, medium, and high conditions, and for each of the 50 water years with the BPA model. Comparing the total variable production costs for year 2010 for alternatives A1 and A3 shows that with the A3 alternative the variable costs increase by $160 million and $202.6 million for the BPA and PROSYM models, respectively.

**Table 16**
**Hydropower Analysis:**
**System Production Costs Summary - Variable Costs**
**Year 2010, With HYDROSIM & BPA Model, Medium Forecast**

| Type of Plant | aMW | Variable Costs (1998 $ Millions) | Average Var Costs (mills/kWh) |
|---|---|---|---|
| **Variable Production Cost Summary With Alternative A1** | | | |
| PNW Plants: | | | |
| High Cost Coal | 647 | 98.7 | 17.40 |
| Low Cost Coal | 2,414 | 207.0 | 9.79 |
| Existing CT | 55 | 11.2 | 23.26 |
| Existing CC | 1,594 | 214.7 | 15.37 |
| New Region CC | 5,135 | 609.4 | 13.55 |
| Regional Firm Imports | 1,477 | 120.0 | 9.27 |
| Regional Hydropower | 15,701 | -- | -- |
| Curtailment/Demand- Side | 89 | 48.7 | 62.72 |
| Total PNW | 27,113 | 1,309.7 | |
| PSW Plants: | | | |
| Existing Resources | 8,066 | 1,654.4 | 23.41 |
| New Region CC | 3,075 | 388.3 | 14.42 |
| Curtailment/Demand-Side | 103 | 50.9 | 56.21 |
| Total PSW | 11,244 | 2,093.7 | |
| Transmission Costs | | 31.5 | |
| Total Variable Costs | | 3,434.9 | |

| **Variable Production Cost Summary With Alternative A3** | | | |
|---|---|---|---|
| PNW Plants: | | | |
| High Cost Coal | 659 | 100.4 | 17.40 |
| Low Cost Coal | 2,436 | 208.8 | 9.79 |
| Existing CT | 53 | 10.8 | 23.26 |
| Existing CC | 1,658 | 223.4 | 15.37 |
| New Region CC | 6,063 | 722.9 | 13.61 |
| Regional Firm Imports | 1,480 | 120.3 | 9.27 |
| Regional Hydropower | 14,477 | -- | -- |
| Curtailment/Demand- Side | 78 | 42.9 | 63.10 |
| Total PNW | 26,904 | 1,429.5 | |
| PSW Plants: | | | |
| Existing Resources | 8,249 | 1,692.6 | 23.42 |
| New Region CC | 3,094 | 390.7 | 14.42 |
| Curtailment/Demand-Side | 111 | 54.9 | 56.52 |
| Total PSW | 11,454 | 2,138.2 | |
| Transmission Costs | | 27.5 | |
| Total Variable Costs | | 3,595.3 | |

| **Differences From A1 (A3-A1)** | | | |
|---|---|---|---|
| PNW Plants: | | | |
| Must Run | -- | -- | |
| High Cost Coal | 12 | 2 | |
| Low Cost Coal | 21 | 2 | |
| Existing CT | (2) | (0) | |
| Existing CC | 64 | 9 | |
| New Region CC | 928 | 114 | |
| Regional Firm Imports | 3 | 0 | |
| Regional Hydropower | (1,225) | -- | |
| Curtailment/Demand- Side | (11) | (6) | |
| Total PNW | (209) | 120 | |
| PSW Plants: | | | |
| Must Run | -- | -- | |
| Existing Resources | 183 | 38 | |
| New Region CC | 19 | 2 | |
| Curtailment/Demand-Side | 7 | 4 | |
| Total PSW | 209 | 45 | |
| Transmission Costs | | (4) | |
| Total Variable Costs | | 160.4 | |

The results of the BPA model as shown in Table 16 are provided by resource type in the PNW. Some thermal plants in the PNW are classified as must run thermal which must be run due to the nature of the plant (*i.e.*, nuclear) or long term contracts which require a constant level of production except during routine re-fueling and scheduled maintenance periods. The generation from these plants will not vary with the different alternatives, so the variable costs are not included in the table. The generation and variable costs from PSW resources are presented in total in this table. The amount of generation from new CC plants is shown for alternatives A1 and A3. However, more new CC plants were assumed to be constructed with A3 to replace some of the lost hydropower generation and capacity. The costs associated with transmitting energy between regions are also reported in this table.

One point of importance is how the loss in hydropower with A3 (and other alternatives) is accounted for in these models. From Table 16 it can be seen that the HYDROSIM model estimated that with alternative A3 that the amount of hydropower production was less than with A1 by 1,225 average MW. This difference in hydropower generation was made up by a combination of thermal alternatives (primarily natural gas-fired combined-cycle combustion turbines) at a higher cost. It is these higher variable costs that made up the increased production costs, and a large component of the net economic effects.

Table 16 demonstrates that with the breaching of the four Lower Snake River dams and the building of additional CC plants in the PNW, the total generation in the PNW in year 2010 will be 209 aMW less than in the base condition. At the same time, the generation in the PSW will increase by 209 aMW to meet the 2010 loads in the PNW and PSW regions. So, on an annual basis, the PNW will import an additional 209 aMW from the PSW in 2010 with alternative A3.

The system variable production costs shown in Table 17 from the PROSYM model is the combination from each of the 14 transmission areas within the WSCC.

The variable costs for hydropower generation in both power production cost models are shown as zero for all alternatives. This is because there is no cost of fuel for hydropower. It is recognized that there will be some differences in fixed O&M and capital costs for hydropower between the different alternatives, but these are not included in this hydropower analysis. The implementation costs analysis does include the differences in hydropower O&M and capital costs with all alternatives and including them in this hydropower analysis would have resulted in double-counting this impact. The interested reader is referred to the Implementation Cost section of this Appendix.

**Fixed Production Costs.** This section discusses the capacity costs, or the fixed costs. For either of the production cost models to meet the loads projected over time, new generating facilities will need to be constructed. With each alternative, a different mix of new generating facilities will be needed to account for the varying amounts of hydropower production. The decision of when and how much new capacity is to be built is an important element of the analysis.

On a simplified basis the market driven capacity addition decisions will probably be based on the following considerations. The market-clearing price for any selected time period will generally be based on the marginal costs of the last resource. Only during periods of extremely high demand (peak demand), typically on very hot summer (or cold winter) days, when the demand for electricity approaches the available generating capacity, would prices rise above the marginal costs of the most expensive generator operating. Because the amount of capacity available at any point in time is fixed, and new generating capacity cannot be built quickly, the only way in which demand and supply could be kept in balance during extremely high demand periods would be through an increase in the price, to a level that would encourage some consumers to reduce their usage. The frequency of these periods of high prices will help determine whether new generating resources will be built. The price adjustment during periods of peak demand can be thought of as representing the value consumers place on reliability.

This price signaling concept and the frequency of occurrence formed the decision criteria for construction of new resources in the BPA and Aurora models used in this power analysis. With these models new resources are assumed to be built when the marginal costs are sufficiently high and frequent to cover the cost of constructing the resource (in terms of the annualized fixed costs) and the variable operating costs. The BPA model, for example, first simulates each year without any new resources being added in that year. The model then tests to see if it is economically justified to add new resources. To be justified a new power unit must produce enough energy in that year at the marginal costs to equal or exceed the fixed and variable costs of the new resource. If the resource is economically justified it is added to resource mix and the model continues this process until an optimized amount of new resources is identified.

This economic justification approach was used in this study to estimate how many new resources would be built with each of the study alternatives, on a year-by-year basis from the present to year 2017. The additional fixed costs are included as a component of the total system production cost for identifying the net economic effects of each alternative. These costs are similar to the traditional capacity costs identified in past studies. Table 25 presents the resource additions projected to occur based on the BPA model results, which were also used in the PROSYM analysis.

**Table 25**
**Power Resource Additions By Alternative**
**BPA Model Results for Specific Years**

| Alternative | 2010 | | | 2018 | | |
|---|---|---|---|---|---|---|
| | PNW | PSW | Total | PNW | PSW | Total |
| A1 | 5,390 | 3,260 | 8,650 | 8,720 | 8,770 | 17,490 |
| A2 | 5,380 | 3,190 | 8,570 | 8,710 | 8,760 | 17,470 |
| A3 | 6,210 | 3,260 | 9,470 | 9,700 | 8,750 | 18,450 |
| A5 | 6,080 | 3,260 | 9,340 | 9,610 | 8,820 | 18,430 |
| A6a | 5,410 | 3,210 | 8,620 | 8,610 | 8,770 | 17,380 |
| A6b | 5,480 | 3,200 | 8,680 | 8,680 | 8,770 | 17,450 |
| **Difference From Base Condition (aMW)** | | | | | | |
| A2 | (10 | (70) | (80) | (10) | (10) | (20) |
| A3 | 820 | -- | 820 | 980 | (20) | 960 |
| A5 | 690 | -- | 690 | 890 | 50 | 940 |
| A6a | 20 | (50) | (30) | (110) | -- | (110) |
| A6b | 90 | (60) | 30 | (40) | -- | (40) |
| **Difference From Base Condition (MW)** | | | | | | |
| A2 | (10) | (80) | (90) | (10) | (10) | (20) |
| A3 | 890 | -- | 890K | 1,070 | (20) | 1,040 |
| A5 | 750 | -- | 750 | 970 | 50 | 1,020 |
| A6a | 20 | (50) | (30) | (120) | -- | (120) |
| A6b | 100 | (70) | 30 | (40) | -- | (40) |

[1]Includes all capacity additions up to and including this year.

**Total System Production Costs.** Table 19 summarizes the total system production costs compared to A1 from the two models for year 2010, the medium projection condition, and the average over all water years. The total system production costs includes the variable costs of operating all the resources in year 2010 (column 2) and the fixed costs (column 4) associated with the additions of new resources that are needed to meet the projected load in that year. The variable costs in any given year include the operating costs for the resources added that year, and all resources in place in that year including new resources built prior to that date. The fixed costs are the annualized capital costs of new capacity. For example, with the BPA model the A3 alternative 820 average MW of new capacity was added up to year 2010 over the base condition. The annual fixed costs of this additional capacity was $88 million. The total system production costs in 2010 for A3 were the combination of the variable costs of $160 million and the fixed costs of $88 million.

**Table 19**
**Hydropower Analysis:**
**Total System Production Cost Summary**
**Year 2010 Simulation - Medium Forecast Conditions**
**Costs Compared to Alternative A1**

| Alternative | Variable Production Costs (1998 $ Million) | Additional CC Capacity[1] (aMW) | Additional Annual Fixed Costs (1998 $ Million) | Total System Production Costs (1998 $ Million) |
|---|---|---|---|---|
| **HYDROSIM and BPA Models** | | | | |
| A2 | $(0) | (80) | $(8) | $(8) |
| A3 | (160 | 820 | $88 | $248 |
| A5 | $169 | 690 | $75 | $244 |
| A6a | $(16) | (30) | $(4) | $(20) |
| A6b | $(4) | 30 | $3 | $(1) |
| **HYSSR and PROSYM Models** | | | | |
| A2 | | | | |
| A3 | $203 | 820 | $77 | $280 |
| A5 | | | | |
| A6a | | | | |
| A6b | | | | |

[1]Includes all capacity additions up to and including this year. This is average MW. To determine total new capacity, divide by the availability factor of 92%. For example, for A3, the new capacity up to and including 2010 is 890 MW (820/.92).

Table 20 presents the system production costs on a year-by-year basis for the medium projection condition. This table also provides the total present worth values for each alternative and the average annual costs based on the three different discount rates. Table 21 provides the average annual production cost for each alternative and the low, medium, and high projection conditions.

**Table 20**
**Hydropower Analysis: Total System Production Costs Over Time**
**Differences from Alternative A1**
**1998 Real Million Dollars, Starting at In-Service Date**
**Medium Production Cost Assumptions**

| Year | A2 | A3 | A5 | A6a | A6b |
|---|---|---|---|---|---|
| **HYDROSIM and BPA Models** | | | | | |
| 2005 | $0 | $0 | $0 | $0 | $0 |
| 2006 | $0 | $0 | $0 | $0 | $0 |
| 2007 | $0 | $242 | $238 | ($20) | ($1) |
| 2008 | ($8) | $244 | $240 | ($20) | ($1) |
| 2009 | ($8) | $246 | $242 | ($20) | ($1) |
| 2010 | ($8) | $248 | $244 | ($20) | ($1) |
| 2011 | ($8) | $249 | $245 | ($21) | ($1) |
| 2012 | ($9) | $251 | $247 | ($21) | ($1) |
| 2013 | ($9) | $253 | $249 | ($21) | ($1) |
| 2014 | ($9) | $254 | $251 | ($21) | ($1) |
| 2015 | ($9) | $257 | $253 | ($21) | ($1) |
| 2016 | ($9) | $259 | $255 | ($21) | ($1) |
| 2017 | ($9) | $261 | $257 | ($22) | ($1) |
| 2018 | ($9) | $261 | $257 | ($22) | ($1) |
| 2019-2104 | ($9) | $261 | $257 | ($22) | ($1) |
| **Results** | | | | | |
| NPV at 0% | ($936) | $25,963 | $25,594 | ($2,167) | ($98) |
| NPV at 4.75% | ($191) | $5,347 | $5,268 | ($444) | ($22) |
| NPV at 6.875% | ($132) | $3,705 | $3,650 | ($307) | ($16) |
| Avg Annual at 0% | ($9) | $260 | $256 | ($22) | ($1) |
| Avg Annual at 4.75% | ($9) | $256 | $253 | ($21) | ($1) |
| Avg Annual at 6.875% | ($9) | $255 | $251 | ($21) | ($1) |

| HYSSR and PROSYM | | | | | |
|---|---|---|---|---|---|
| 2005 | | $0 | | | |
| 2006 | | $0 | | | |
| 2007 | | $239 | | | |
| 2008 | | $253 | | | |
| 2009 | | $266 | | | |
| 2010 | | $280 | | | |
| 2011 | | $283 | | | |
| 2012 | | $286 | | | |
| 2013 | | $289 | | | |
| 2014 | | $291 | | | |
| 2015 | | $294 | | | |
| 2016 | | $297 | | | |
| 2017 | | $300 | | | |
| 2018 | | $300 | | | |
| 2019-2104 | | $300 | | | |
| **Results** | | | | | |
| NPV at 0% | | $29,779 | | | |
| NPV at 4.75% | | $5,526 | | | |
| NPV at 6.875% | | $3,658 | | | |
| Avg Annual at 0% | | $298 | | | |
| Avg Annual at 4.75% | | $265 | | | |
| Avg Annual at 6.875% | | $252 | | | |

**Table 21**
**Hydropower Analysis:**
**Average Annual Total System Production Costs**
**Results From Two Different Models**
**1998 Real Million Dollars, Various In-Service Dates, 100-Year Analysis**
**All Amounts are Cost Differences From Alternative A1**

| Production Costs HYDROSIM & BPA Model | | | | Production Costs HYSSR and PROSYM | |
|---|---|---|---|---|---|
| **Alternative** | **Low** | **Medium** | **High** | **Alternative** | **Medium** |
| **Average Annual Costs at Discount Rate 6.875%** | | | | | |
| A2 | ($6) | ($9) | ($12) | A2 | |
| A3 | $187 | $255 | $329 | A3 | $252 |
| A5 | $184 | $251 | $307 | A5 | |
| A6a | ($19) | ($21) | ($31) | A6a | |
| A6b | ($2) | ($1) | ($6) | A6b | |
| **Average Annual Costs at Discount Rate 4.75%** | | | | | |
| A2 | ($6) | ($9) | ($12) | A2 | |
| A3 | $187 | $256 | $332 | A3 | $265 |
| A5 | $184 | $253 | $310 | A5 | |
| A6a | ($19) | ($21) | ($31) | A6a | |
| A6b | ($2) | ($1) | ($6) | A6b | |
| **Average Annual Costs at Discount Rate 0%** | | | | | |
| A2 | ($6) | ($9) | ($13) | A2 | |
| A3 | $186 | $260 | $339 | A3 | $298 |
| A5 | $184 | $256 | $316 | A5 | |
| A6a | ($19) | ($22) | ($32) | A6a | |
| A6b | ($2) | ($1) | ($6) | A6b | |

The comparison of the BPA and PROSYM production cost models can be made with results shown in Tables 19 and 20. Because PROSYM is much more complicated model to operate, and the results were similar to the BPA model, it was not run for all study alternatives. PROSYM modeling was limited to the medium forecast conditions and average water year. Consequently, many of the tables in this section do not include PROSYM results for all scenarios. However, the study team considered the PROSYM results to be a valuable crosscheck of the other modeling results and it was a useful tool to test many elements of this study.

**3.2.6.2 Market Price Analysis.** The electric industry is moving towards a more competitive market, but is currently in a transition period which mixes wholesale pricing at marginal costs with most retail pricing based on average costs, and established contracts that may or not reflect either of these approaches. For these reasons, this report provides results from the two approaches of system production costs in the previous section and the market prices in this section.

To evaluate each of the alternatives, the market prices from Aurora, as defined by the marginal costs, are applied to the difference in PNW hydropower generation from the base condition (A1). Since the marginal cost varies by transmission area and by time periods, the study team had to select which market prices would be most appropriate to evaluate impacts. The study team chose to multiply changes in PNW hydropower generation by the Aurora market price developed for the states of Oregon and Washington. This price most accurately reflects the value of PNW energy.

The marginal costs vary by hour, by day, and by month. To simplify the analysis hourly prices were allocated to peak and non-peak periods and averaged for each month to obtain estimates of peak and off-peak prices. Table 22 provides the monthly on-peak and off-peak market price defined by Aurora, for the medium projection condition, for the two specific years of 2005 and 2010, in nominal prices and real 1998 dollars.

**Table 22**
**Hydropower Analysis:**
**Average Market-Clearing Prices From NPPC Study**
**Medium Projection Condition for Two Years**
**(mills/kWh)**

| Month | On-Peak Nominal | Off-Peak Nominal | On-Peak 1998 $ | Off-Peak 1998 $ |
|---|---|---|---|---|
| **Year 2005** | | | | |
| Sep | 42.39 | 31.55 | 35.66 | 26.54 |
| Oct | 32.32 | 28.60 | 27.19 | 24.06 |
| Nov | 33.78 | 28.14 | 28.42 | 23.68 |
| Dec | 37.58 | 32.81 | 31.62 | 27.60 |
| Jan | 36.87 | 32.46 | 31.02 | 27.30 |
| Feb | 34.63 | 29.97 | 29.13 | 25.21 |
| Mar | 26.77 | 26.35 | 22.52 | 22.17 |
| Apr | 25.95 | 20.02 | 21.83 | 16.84 |
| May | 20.05 | 18.17 | 16.87 | 15.29 |
| Jun | 24.37 | 17.59 | 20.50 | 14.80 |
| Jul | 32.10 | 25.32 | 27.00 | 21.30 |
| Aug | 43.39 | 31.32 | 36.50 | 26.35 |
| Average | 32.52 | 26.86 | 27.36 | 22.60 |
| **Year 2010** | | | | |
| Sep | 54.40 | 32.79 | 40.45 | 24.38 |
| Oct | 32.89 | 29.29 | 24.45 | 21.78 |
| Nov | 36.13 | 31.01 | 26.87 | 23.06 |
| Dec | 39.13 | 32.77 | 29.09 | 24.37 |
| Jan | 37.78 | 35.20 | 28.09 | 26.18 |
| Feb | 38.83 | 31.05 | 28.88 | 23.09 |
| Mar | 36.58 | 27.14 | 27.20 | 20.18 |
| Apr | 31.01 | 20.16 | 23.06 | 14.99 |
| May | 18.81 | 18.44 | 13.99 | 13.71 |
| Jun | 22.05 | 17.56 | 16.40 | 13.06 |
| Jul | 27.06 | 27.61 | 20.12 | 20.53 |
| Aug | 41.35 | 39.91 | 30.74 | 29.67 |
| Average | 34.67 | 28.58 | 25.78 | 21.25 |

The average monthly prices for peak and non-peak were used to identify the economic effects associated with changes in hydropower generation. This was done by computing the change in hydropower generation from the current conditions, by subtracting the PNW hydropower generation with each alternative from the base condition (alternative A1). Adjustments were also made to the monthly hydropower generation by separating it into peak and non-peak hours based on the historic distribution shaping of the monthly hydropower generation. Table 6 presented the hydropower generation changes for each alternative based on average monthly generation. Table 23 multiplies the projected market price (from Table 22) by the changes in hydropower output from the base condition using both HYSSR and HYDROSIM outputs. This table labels the economic effects as net economic costs to represent changes from the base condition.

**Table 23**
**Hydropower Analysis:**
**Net Economic Costs Computed From Market Prices**
**(Market Clearing Price Multiplied by Change in Hydropower)**
**Differences From Alternative A1**
**1998 Real Million Dollars, Starting At In-Service Date**
**Medium Condition Projections**

| Year | A2 | A3 | A5 | A6a | A6b |
|---|---|---|---|---|---|
| **HYDROSIM** | | | | | |
| 2005 | $0 | $0 | $0 | $0 | $0 |
| 2006 | $0 | $0 | $0 | $0 | $0 |
| 2007 | $0 | $237 | $223 | ($19) | $0 |
| 2008 | ($8) | $227 | $209 | ($18) | ($0) |
| 2009 | ($8) | $226 | $210 | ($14) | ($0) |
| 2010 | ($7) | $223 | $207 | ($14) | ($0) |
| 2011 | ($7) | $231 | $217 | ($15) | $0 |
| 2012 | ($7) | $226 | $212 | ($18) | $0 |
| 2013 | ($7) | $223 | $207 | ($17) | ($0) |
| 2014 | ($7) | $222 | $204 | ($16) | ($1) |
| 2015 | ($7) | $218 | $198 | ($14) | ($1) |
| 2016 | ($7) | $222 | $205 | ($13) | ($0) |
| 2017 | ($7) | $216 | $198 | ($17) | ($0) |
| 2018 | ($7) | $216 | $198 | ($17) | ($0) |
| 2019-2104 | ($7) | $216 | $198 | ($17) | ($0) |
| **Results** | | | | | |
| NPV at 0% | ($698) | $21,719 | $19,933 | ($1,709) | ($31) |
| NPV at 4.75% | ($148) | $4,586 | $4,224 | ($347) | ($5) |
| NPV at 6.875% | ($104) | $3,213 | $2,964 | ($240) | ($4) |
| Avg Annual at 0% | ($7) | $217 | $199 | ($17) | ($0) |
| Avg Annual at 4.75% | ($7) | $220 | $203 | ($17) | ($0) |
| Avg Annual at 6.875% | ($7) | $221 | $204 | ($17) | ($0) |

| HYSSR | | | | | |
|---|---|---|---|---|---|
| 2002 | $0 | $0 | $0 | $0 | $0 |
| 2003 | $0 | $0 | $0 | $0 | $0 |
| 2004 | $0 | $0 | $0 | $0 | $0 |
| 2005 | $0 | $0 | $0 | $0 | $0 |
| 2006 | $0 | $0 | $0 | $0 | $0 |
| 2007 | $0 | $228 | $215 | ($21) | ($2) |
| 2008 | ($10) | $235 | $224 | ($20) | ($3) |
| 2009 | ($10) | $230 | $219 | ($20) | ($3) |
| 2010 | ($10) | $227 | $215 | ($21) | ($3) |
| 2011 | ($10) | $227 | $213 | ($22) | ($2) |
| 2012 | ($10) | $223 | $207 | ($21) | ($3) |
| 2013 | ($10) | $226 | $213 | ($20) | ($3) |
| 2014 | ($9) | $220 | $207 | ($20) | ($3) |
| 2015 | ($9) | $220 | $207 | ($19) | ($3) |
| 2016 | ($9) | $220 | $207 | ($21) | ($2) |
| 2017 | ($9) | $220 | $207 | ($21) | ($3) |
| 2018 | ($9) | $220 | $207 | ($21) | ($3) |
| 2019-2104 | ($9 | $220 | $207 | ($21) | ($3) |
| **Results** | | | | | |
| NPV at 0% | ($943) | $22,109 | $20,761 | ($2,056) | ($297) |
| NPV at 4.75% | ($199) | $4,672 | $4,396 | ($428) | ($60) |
| NPV at 6.875% | ($140) | $3,274 | $3,083 | ($298) | ($41) |
| Avg Annual at 0% | ($9) | $221 | $208 | ($21) | ($3) |
| Avg Annual at 4.75% | ($10) | $224 | $211 | ($21) | ($3) |
| Avg Annual at 6.875% | ($10) | $225 | $212 | ($21) | ($3) |

Table 24 provides the average annual net economic costs based on the market price analysis, by different discount rates, by the two hydro-regulation models, and for the high, medium, and low economic forecast conditions. The values in this table were based on the differences from the base condition (A1). The results from the different hydro-regulation models of HYDROSIM and HYSSR are not significantly different.

**Table 24**
**Hydropower Analysis:**
**Average Annual Net Economic Costs From Market Prices**
**1998 Real Million Dollars, Various In-Service Dates, 100-Year Analysis**
**All Amounts are Cost Differences From Alternative A1**

| HYDROSIM and AURORA Prices | | | | HYSSR and AURORA Prices | | | |
|---|---|---|---|---|---|---|---|
| Alternative | Low | Medium | High | Alternative | Low | Medium | High |
| **Average Annual Costs at Discount Rate 6.875%** | | | | | | | |
| A2 | ($5) | ($7) | ($12) | A2 | ($7) | ($10) | ($16) |
| A3 | $151 | $221 | $347 | A3 | $154 | $225 | $353 |
| A5 | $140 | $204 | $328 | A5 | $146 | $212 | $338 |
| A6a | ($10) | ($17) | ($27) | A6a | ($14) | ($21) | ($30) |
| A6b | $0 | ($0) | $1 | A6b | ($2) | ($3) | ($5) |
| **Average Annual Costs at Discount Rate 4.75%** | | | | | | | |
| A2 | ($5) | ($7) | ($12) | A2 | ($7) | ($10) | ($16) |
| A3 | $148 | $220 | $347 | A3 | $151 | $224 | $353 |
| A5 | $138 | $203 | $327 | A5 | $143 | $211 | $337 |
| A6a | ($10) | ($17) | ($27) | A6a | ($13) | ($21) | ($30) |
| A6b | $0 | ($0) | $1 | A6b | ($2) | ($3) | ($5) |
| **Average Annual Costs at Discount Rate 0%** | | | | | | | |
| A2 | ($5) | ($7) | ($12) | A2 | ($6) | ($9) | ($16) |
| A3 | $141 | $217 | $346 | A3 | $143 | $221 | $353 |
| A5 | $132 | $199 | $325 | A5 | $136 | $208 | $336 |
| A6a | ($10) | ($17) | ($27) | A6a | ($13) | ($21) | ($30) |
| A6b | $0 | ($0) | $1 | A6b | ($2) | ($3) | ($5) |

**3.2.6.3 Reliability and Capacity Effects.** This section describes how the changes in the hydropower capacity in the PNW were investigated. Of particular interest is how will hydropower capacity reductions impact the generation reliability in the region and the WSCC in total, and to what extent additional thermal capacity will be built to replace losses in hydropower capacity.

Several important elements of this generation reliability approach had to be considered by the study team. Of most interest in this analysis was: 1) the treatment of load in periods in which existing resources were insufficient to meet load demand; 2) consideration of system reserves requirements and dependable capacity; and 3) the type and price of new resources. All of these concerns relate to how the lost hydropower will be replaced with replacement generating resources.

The study team was concerned whether different levels of replacement capacity and different approaches to the treatment of unserved loads would significantly change the estimates of increased system production costs. These two factors were tested with different approaches that lead to different levels of new capacity and planning reserve margins. With the higher levels of new replacement generating capacity, the planning reserves were higher but so were the system production costs. However, it was found that the total system production costs did not vary significantly (on a percentage basis) with the different levels of assumed new generating capacity. So, the study team was satisfied that the capacity addition approach used in this analysis represented a reasonable estimate of the economic effects associated with the alternatives.

### 3.2.7 System Transmission Effects

The analysis of power system effects up to this point assumed that transmission reliability and service would remain the same under all alternatives. The purpose of this section is to identify the costs associated with maintaining transmission reliability with all the alternatives. This section investigates the impacts to the Northwest transmission grid with alternatives A3 and A5. The A2 and A6 alternatives are not expected to have any significant impact to the transmission grid.

The A3 and A5 alternatives would breach the four Lower Snake dams, rendering the powerhouses inoperable, and thereby altering the source of power generation that feeds into the Northwest transmission grid. Since the transmission grid was originally constructed in combination with the generation system and since they interact electrically, loss of generation will affect the transmission system's ability to move bulk power and serve regional loads.

The transmission analysis looked at transmission system impacts with and without replacement generation. Both transmission system reinforcements and generation additions were evaluated to mitigate the transmission system impacts caused by breaching the four Lower Snake dams. The initial phase of this transmission study assumed no replacement generation for the dams that are breached. The transmission improvements needed to maintain reliable service were then identified and costs estimates were prepared. However, it was recognized that the construction and location of replacement generating resources would have a profound effect on the transmission system impacts and reinforcement needs and may provide a most cost-effective solution. This phase of the study was done separately from the energy supply additions shown in Table 25. The energy supply studies indicated that alternatives A3 and A5 require 890 MW of new CC generation in 2010 to replace lost hydropower. This transmission study evaluated transmission system requirements if replacement generation were constructed in a location where it would provide transmission system benefits to mitigate the loss of hydropower. To the extent that more than 890 MW of new CC generation will be required for transmission reliability, the additional costs are added to the transmission impacts.

Preliminary cost estimates for capital additions are included in this summary. These costs are based on preliminary studies using typical costs for facilities. A range of cost is given since there is much uncertainty about the scope of the projects, routes, etc which could affect project cost.

Transmission impacts were examined for two seasonal conditions, the summer and the winter peak situations. The following defines the expected impacts and the possible solutions. The study approach was to first identify the impact to the transmission system, then the possible solutions were examined. The final step of the analysis was to select the most cost-effective measure to address the identified transmission impact.

**3.2.7.1 Summer Impacts.** The summertime peaks are the largest in the PSW and transmission from the PNW over the California-Oregon Intertie/Pacific Direct Current Intertie (COI/PDCI) is important to meeting the PSW demands.

**Northwest to California Transfers.** If the Lower Snake dams are breached, and not replaced, the COI/PDCI transfers limits decrease by 200 MW (from 7200 to 7000 MW). This would limit the ability to sell and transfer PNW generation to the PSW to meet peak demands. Three possible solutions were postulated: 1) reduce the COI/PDCI capacity by 200 MW and incur loses in sales. The economic costs of this approach were not quantified. 2) Upgrade the COI/PDCI intertie to maintain its capacity at a cost of $65 million to $85 million. 3) Site thermal replacement plants in the locations that would reinforce intertie transfer capabilities. Further study of summer solutions to the NW to California impacts was not done since it was realized that the solutions to the summer impacts may be unnecessary because the solutions to the winter problems could also correct the summer impacts.

**Northwest Regional Impacts.** With the loss the four Lower Snake dams, there is more stress on the transfer capability in the Upper Mid-Columbia area. Two transmission system cutplanes, North of John Day and North of Hanford are impacted. (A cutplane is a group of transmission lines whose total loading is an indicator of system stress.) These particular cutplanes measure how much power is flowing from the Upper and Mid Columbia area to COI/PDCI. With the elimination of generation from the Lower Snake Projects and a desire to have the same level of north to south transfers on the COI/PDCI, the flow across the cutplanes must increase. In other words, the generation from the Lower Snake Projects is replaced with generation from Chief Joseph, Grand

Coulee and other northern and eastern powerplants. However, with this increase in generation, capacities across these cutplanes are exceeded. Thus, the cutplane flows must be limited, which in turn causes a reduction in the COI/PDCI transfer capability. To increase cutplane capability an improvement to the Schulz-Hanford transmission line and facilities is required. The estimated costs were $50 to $75 million.

**Montana to Northwest Transfer Capability.** The West of Hatwai capability is reduced about 500 MW if the Lower Snake dams are breached. This means that transfers from Montana and/or Western Montana Hydro will need to be reduced to maintain the Hatwai limit. Previous studies have shown that these problems would be mitigated with a Bell-Ashe 500-kilovolt (kV) line from Spokane to the Tri-Cities area. This line would require a new transmission corridor and cost between $100 million to $150 million.

**Summer Load Service.** The Tri-Cities area, south of Spokane and Central Washington load areas are negatively affected by dam removal scenarios. Specific transmission impacts are different depending on the location of replacement generation. These include the new Schultz-Hanford line ($50 to $75 million) and reconductoring or rebuilding various other lower voltage lines at an estimated cost of $10 to 20 million. Additional voltage support is also needed in the Tri-Cities area if the four Lower Snake dams are breached. Converting the generators at a hydropower plant to synchronous condensers is an effective way to produce reactive support required to fix this voltage support problem for Tri-Cities area loads. This could be accomplished with converting the generators at Ice Harbor. Preliminary cost estimates for this conversion were $2 to $6 million.

**3.2.7.2 Winter Impacts.** The impacts to the transmission system under extreme winter load conditions in the PNW were examined. An extreme cold winter load condition was examined since stress on the system is high under extreme weather. The extreme cold winter load level is an abnormal cold condition (arctic express) with minimum temperatures that have a 5% probability of occurring. The extreme cold winter load level is approximately 12% higher than the expected normal winter peak that has a 50% probability of occurring. This is the criteria BPA customers have agreed to in the past.

It was found that imports from the California interties could not meet the shortfall created by the loss of the Lower Snake dams. The import capability today on the COI/PDCI with the dams in place is around 2,400 MW during extreme winter load conditions. This 2,400 MW capability is needed today, with the four Lower Snake dams in place, to augment available generation and spinning reserve requirements in the PNW. Without the four Lower Snake dams, either more intertie, or more local generation is required to meet system loads and maintain system reliability. The possible solutions examined were to develop replacement generation or to improve the COI/PDCI. The analysis shows that replacement generation is about half as costly as intertie transmission improvements.

**PNW Replacement Generation.** With the removal of the Lower Snake River dams it was found that 1,550 MW of new generating resources (replacement generation) strategically located in the PNW would be sufficient to meet the winter extreme conditions, if the COI/PDCI was not improved. This is about 510 MW more of replacement generation than is required for energy alone.

The new capacity assumed to be built in the future to replace energy lost under alternatives A3 and A5 was described in Table 25. The net economic costs identified in this technical report for A3 were based on adding 890 MW of new PNW generating resources by year 2010 and 1,040 MW by year 2018. But this takes care of only regional energy losses at the breached dams. The winter transmission impacts of breaching could be mitigated if 1,550 MW of replacement generating resources were in place at the time of breaching of the Lower Snake River Dams (2007). The transmission system impacts of breaching would require more generation in place sooner (1,550 MW in 2006 versus 890 MW in 2010 and 1,040 in 2018).

The costs of providing additional replacement generation were examined using the system production cost approach as computed by the BPA model. The replacement capacity assumed to be built elsewhere in this analysis was 1,040 MW through year 2018 as shown in Table 25. So, to maintain the same transmission reliability an additional 510 MW (1,550 - 1,040) of generation capacity will need to be constructed in PNW. Based on the CC construction costs of $601,000 per MW, the additional construction costs of replacement thermal will be about $306 million. These increased costs will be somewhat offset by the expected reduction in system variable costs from adding more generation than is required for energy alone. The annual equivalent economic costs associated with the additional generation capacity were $8.9 million at the 6.875% discount rate.

**Improvements to COI/PDCI.** The alternative solution to building new replacement capacity is intertie transmission system reinforcements. The improvements needed to meet load service requirements for extreme winter conditions include: a second Captain Jack-Meridian 500-kV line (a cross cascades line from Klamath Falls to Medford) and a second Big Eddy-Ostrander 500-kV line (a cross cascades line from The Dalles to Portland. Both of these new line additions need to be on separate right of way for the existing lines due to reliability reasons. The construction costs for a second Captain Jack Meridian line were estimated at $80 to $130 million. The addition of a second Big Eddy-Ostrander line would cost from $70 to $120 million. The average annual costs of these two lines considering O&M, Replacements, and Repair, computed at 6.875%, were $5.6 to $9.0 million for Captain Jack Meridian and $4.9 to $8.3 million for Big Eddy-Ostrander. The mitigation costs of the transmission solution are about twice as expensive as the generation solution.

**Winter Local Load Service Limitations.** There are also wintertime load service limitations in the Tri-Cities area for extreme cold winter conditions if the Lower Snake dams are breached. A new 230/115-kV transformer in the Franklin area would be required. The estimated cost for adding this transformer is between $15 million and $25 million.

**3.2.7.3 Summary of Transmission Impacts.** Table 28 provides the possible solutions and related annual costs based on the 6.875% discount rate. The table is broken into the impact areas and possible solutions. For each impact the lowest cost solution is recommended and included in the total economic effects.

**Table 28**
**Hydropower Analysis:**
**Transmission Impacts with Alternative A3**
**Annual Values Based on 6.875%**

| Timing/ Location of Impacts | Impact Description | Possible Solutions | Estimated Construction Costs ($ millions) | Incremental O&M Costs ($ millions) | Total Annual Costs ($ millions) | Selected Solution Average Annual Costs ($ millions) |
|---|---|---|---|---|---|---|
| Summer: NW to California | Transfer limit is reduced (a cutplane problem) | Limit COI/PDCI transfer capability from 7200 MW to 7000 MW | Not quantified | | | |
| | | Upgrade the COI/PDCI | 65 to 85 | 0.3 | 5.1 to 5.9 | |
| | | Site thermal replacement plants to reduce impact | Not quantified | | | Proper siting 1550 MW for winter could solve this problem |
| Summer: Upper/Mid Columbia Load Service | Thermal overloads | New Schultz-Hanford transmission line | 50 to 75 | 0.17 | 3.6 to 5.2 | 3.6 to 5.2 |
| Summer: Tri-Cities Service | Voltage support to the Tri-Cities | Ice Harbor generators converted to synchronous condensers | 2 to 6 | 0.2 | 0.4 to 0.6 | 0.4 to 0.6 |
| | Load service impacted | Local line transmission improvements | 10 to 20 | 0 | 0.7 to 1.4 | 0.7 to 1.4 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Summer: Montana transfer to Northwest | Transfer limit is reduced by 500 MW | New Bell-Ashe transmission line | 100 to 150 | 0.38 | 7.2 to 10.5 | 7.2 to 10.5 |
| Summer: Canada Transfer to Northwest | Increased congestion on I-5 transmission corridor | No solution offered | Not quantified | | | |
| Winter: Meeting extreme winter loads | Import capability is reduced and results in inability to meet extreme loads | Site 1550 MW of replacement generation | 306 capital costs for generation | Included in annual costs | 8.9 | 8.9 |
| | | New transmission lines - Capt Jack-Meridian | 80 to 130 | 0.2 | 5.6 to 9.0 | |
| | | New transmission lines - Big Eddy-Ostander | 70 to 120 | 0.2 | 4.9 to 8.3 | |
| Winter: Tri-Cities Load Service | Load service limitations | Local transmission improvements, McNary-Franklin | 15 to 20 | 0.1 | 1.1 to 1.5 | 1.1 to 1.5 |
| **Totals[1]** | | | **$483 to $577** | | | **$21.9 to $28.1** |

[1]Includes only costs for selected solutions

Table 28 shows the range of construction costs as estimated by BPA. Also shown are the incremental O&M costs that would occur if the transmission improvements were built. To develop the annual costs associated with these measures a 45-year replacement cycle was assumed. As can be seen from this table the annual costs associated with improvements needed to maintain transmission reliability with the breaching of the four Lower Snake River dams is about $22 to $28 million at 6.875%. Identical summaries were made at 4.75% and 0.0% discounts rates. The annual costs were $19 to $24 million at 4.75% and $16 to $18 million at 0% discount rates.

### 3.2.8 Ancillary Services Effects.

This section discusses the ancillary services and the estimated economic values of these services provided by the four Lower Snake River projects. These ancillary services are in addition to the energy, capacity, and transmission support benefits discussed elsewhere in this report. With the open access transmission ruling of the FERC, power suppliers are now charging for many of the ancillary services that in the past were generally provided without charge by the entities owning the transmission facilities. Starting in 1998 BPA has begun to sell these ancillary services. Since these services are a necessary element of a safe and reliability power system, the loss of these services represents economic costs that must be accounted in this analysis.

The Lower Snake hydropower plants are used for Automatic Generation Control (AGC). Small, but very frequent changes in generation are necessary to perform this function. Hydroelectric projects, with stored water as their fuel, are extremely flexible and very useful for this purpose. If the four dams were removed, their contribution to this system would have to be spread over the remaining projects or replaced from other sources. To value the AGC the BPA staff that deals with market sales of ancillary services were consulted. The economic value of AGC that will be lost with the removal of the Snake River dams were based on the percent of time that AGC is utilized, the MW magnitude, and the market value. The average annual value was estimated to be $465,000.

The four Lower Snake River dams are also used to provide part of the required reserves for the Federal power system. The WSCC has established reserve requirements for all utilities. These contingency reserves are expected to be "on-call" in the event of emergency loss of generating resources in the system. Utilities are required to have both operating and spinning reserves. The spinning reserve units must be synchronized with the power system and provide immediate response, while the operating reserves must be available within 10 minutes. The BPA estimates that the Snake River plants are used for reserves for about one half of the months of December and March, and all of the months of January, February, April, May, and June. The BPA relies on about 300 MW of reserves from these four plants. The market values of these reserve services vary throughout the year. In the high demand winter months it was assumed that BPA would have to purchase reserves from the market at a value of $31/MW-month. During the rest of the year it was assumed BPA would sell this reserve at the average monthly market prices. The annual net economic cost associated with the loss of these reserves was estimated to be $7,183,000.

The total ancillary annual losses for A3 and A5 are the combination of the AGC loss in Table 28 and the loss of reserve value in Table 29. This loss is $7,648,000, annually. This was rounded to $8 million for reporting purposes in the rest of this document.

### 3.2.9 Summary Of Hydropower Net Economic Effects

This section combines all the net economic effects as defined by the medium projection conditions. These represent the most likely point estimates of economic effects. However, because of the uncertainty embedded into many of the key variables, a risk and uncertainty analysis was undertaken to provide range of results. See section ____ for a complete presentation of the uncertainty and variability associated with these estimates.

Table 36 presents the medium results for the two key approaches used to identify the net increases in costs to the power system as compared to the base condition. The costs in the table are the average annual equivalents with different discount rates. The two approaches used in the study were the system production costs and the market pricing approach. Different estimates of net economic costs were made by each of these approaches and models. But, the range of results from minimum to maximum is relatively small. The range is also relatively small over the three discount rates. For example, the annual net costs for the A3 alternative at 6-7/8% % is from $220 to $226 million. While, the results for A3 range from $216 to $226 million over all three discount rates.

**Table 36**
**Hydropower Analysis:**
**Summary of System Costs (Production Costs and Market Prices)**
**Cost Differences From Alternative A1**
**Medium Projections, 1998 $ Million, Average of All Water Conditions**
**Various In-Service Dates, 100-Year Analysis**

| Alternatives | Production Costs | Market Price | | Range of Costs | |
|---|---|---|---|---|---|
| | BPA Model | HYDROSIM | HYSSR | Minimum | Maximum |
| **Discount Rate 6.875%** | | | | | |
| A2 | -9 | -7 | -10 | -10 | -7 |
| A3 | 255 | 221 | 225 | 221 | 255 |
| A5 | 251 | 204 | 212 | 204 | 251 |
| A6a | -21 | -17 | -21 | -21 | -17 |
| A6b | -1 | 0 | -3 | -3 | 0 |

| | | | | | |
|---|---|---|---|---|---|
| **Discount Rate 4.75%** | | | | | |
| A2 | -9 | -7 | -10 | -10 | -7 |
| A3 | 256 | 220 | 224 | 220 | 256 |
| A5 | 253 | 203 | 211 | 203 | 253 |
| A6a | -21 | -17 | -21 | -21 | -17 |
| A6b | -1 | 0 | -3 | -3 | 0 |
| **Discount Rate 0%** | | | | | |
| A2 | -9 | -7 | -9 | -9 | -7 |
| A3 | 260 | 217 | 221 | 217 | 260 |
| A5 | 256 | 199 | 208 | 199 | 256 |
| A6a | -22 | -17 | -21 | -22 | -17 |
| A6b | -1 | 0 | -3 | -3 | 0 |

The total net economic effects are shown in Table 37 for the medium economic forecast condition. This table combines the system costs shown in Table 36 with the transmission reliability effects presented in section 3.2.7 and the ancillary services in section 3.2.8.

**Table 37**
**Hydropower Analysis:**
**Total Average Annual Net Economic Effects**
**Differences From Alternative A1**
**Medium Projections, 1998 $ Million, Average of All Water Conditions**
**Various In-Service Dates, 100-Year Analysis**

| Alternatives | System Costs | | Transmission Reliability Costs | | Ancillary Services Costs | Total Effects | |
|---|---|---|---|---|---|---|---|
| | Minimum | Maximum | Minimum | Maximum | | Minimum | Maximum |
| **Discount Rate 6.875%** | | | | | | | |
| A2 | ($10) | ($7) | $0 | $0 | $0 | ($10) | ($7) |
| A3 | $221 | $255 | $22 | $28 | $0 | $251 | $291 |
| A5 | $204 | $251 | $22 | $28 | $0 | $234 | $287 |
| A6a | ($21) | ($17) | $0 | $0 | $0 | ($21) | ($17) |
| A6b | ($3) | ($0) | $0 | $0 | $0 | ($3) | ($0) |
| **Discount Rate 4.75%** | | | | | | | |
| A2 | ($10) | ($7) | $0 | $0 | $0 | ($10) | ($7) |
| A3 | $220 | $256 | $19 | $24 | $0 | $247 | $288 |
| A5 | $203 | $253 | $19 | $24 | $0 | $230 | $285 |
| A6a | ($21) | ($17) | $0 | $0 | $0 | ($21) | ($17) |
| A6b | ($3) | ($0) | $0 | $0 | $0 | ($3) | ($0) |
| **Discount Rate 0%** | | | | | | | |
| A2 | ($9) | ($7) | $0 | $0 | $0 | ($9) | ($7) |
| A3 | $217 | $260 | $16 | $18 | $0 | $241 | $286 |
| A5 | $199 | $256 | $16 | $18 | $0 | $223 | $282 |
| A6a | ($22) | ($17) | $0 | $0 | $0 | ($22) | ($17) |
| A6b | ($3) | ($0) | $0 | $0 | $0 | ($3) | ($0) |

[1]Specific power is the power output per unit mass of working fluid.