# MARGINAL COST ANALYSIS

# STUDY

PREPARED BY

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## COMMONLY USED ACRONYMS

| | |
|---|---|
| AC | Alternating Current |
| ACME | Accelerated California Market Estimator (computer program) |
| AFUDC | Allowance for Funds Used During Construction |
| aMW | Average Megawatt |
| ASC | Average System Cost |
| ASM | Aluminum Smelter Model |
| BASC | BPA Average System Cost |
| BTU | British Thermal Unit |
| CE | Emergency Capacity (rate) |
| CF | Firm Capacity (rate) |
| CO-OP | Co-operative Electric Utility |
| COB | California-Oregon Border |
| COE | United States Army Corps of Engineers |
| Con/Mod | Conservation Modernization Program |
| COSA | Cost of Service Analysis |
| CSPE | Columbia Storage Power Exchange |
| CT | Combustion Turbine |
| CWIP | Construction Work In Progress |
| CY | Calendar Year (Jan - Dec) |
| DC | Direct Current |
| DOE | Department of Energy |
| DSIs | Direct Service Industrial Customers |
| DSM | Demand-Side Management |
| EA | Environmental Assessment |
| ECC | Energy Content Curve |
| EIS | Environmental Impact Statement |
| ET | Energy Transmission (rate) |
| F & O | Financial and Operating Reports |
| FBS | Federal Base System |
| FCRPS | Federal Columbia River Power System |
| FCRTS | Federal Columbia River Transmission System |
| FELCC | Firm Energy Load Carrying Capability |
| FERC | Federal Energy Regulatory Commission |
| FPT | Formula Power Transmission (rate) |
| FSEA | Federal Secondary Energy Analysis |
| FY | Fiscal Year (Oct - Sep) |
| GCPs | General Contract Provisions |
| GRSPs | General Rate Schedule Provisions |
| GTRSPs | General Transmission Rate Schedule Provisions |
| IDUEIS | Intertie Development and Use Environmental Impact Statement |
| IE | Eastern Intertie Transmission (rate) |

| | |
|---|---|
| IN | Northern Intertie Transmission (rate) |
| IOUs | Investor-Owned Utilities |
| IP | Industrial Firm Power (rate) |
| IR | Integration of Resources (rate) |
| IRE | Industrial Replacement Energy |
| IS | Southern Intertie Transmission (rate) |
| ISAAC | Integrated System for Analysis of Acquisitions (computer program) |
| ISC | Investment Service Coverage |
| KV | Kilovolt (1000 volts) |
| KW | Kilowatt (1000 watts) |
| kWh | Kilowatthour |
| LDD | Low Density Discount |
| LOLP | Loss of Load Probability |
| LTIAP | Long-Term Intertie Access Policy |
| M/kWh | Mills per kilowatthour |
| MC | Marginal Cost |
| MCA | Marginal Cost Analysis |
| MCS | Model Conservation Standards |
| MW | Megawatt (1 million watts) |
| MW-miles | Megawatt-miles |
| MWh | Megawatthour |
| MT | Market Transmission (rate) |
| NEPA | National Environmental Policy Act |
| NF | Nonfirm Energy (rate) |
| NFRAP | Nonfirm Revenue Analysis Program (computer program) |
| NOB | Nevada-Oregon Border |
| NR | New Resource Firm Power (rate) |
| NTSA | Non-Treaty Storage Agreement |
| NWPP | Northwest Power Pool |
| NWPPC | Northwest Power Planning Council |
| O&M | Operation and Maintenance |
| OMB | Office of Management and Budget |
| OY | Operating Year (Jul - Jun) |
| PA | Public Agency |
| PIP | Programs in Perspective |
| PF | Priority Firm Power (rate) |
| PMDAM | Power Market Decision Analysis Model |
| PNCA | Pacific Northwest Coordination Agreement |
| PNUCC | Pacific Northwest Utilities Conference Committee |
| PNW | Pacific Northwest |
| POD | Point of Delivery |
| PSW | Pacific Southwest |
| PURPA | Public Utilities Regulatory Policies Act |
| PUD | Public or Peoples' Utility District |

| | |
|---|---|
| RAM | Rate Analysis Model (computer model) |
| REVEST | Revenue Estimate (computer program) |
| ROD | Record of Decision |
| RP | Reserve Power (rate) |
| RPSA | Residential Purchase and Sale Agreement |
| SAM | System Analysis Model |
| SI | Special Industrial Power (rate) |
| SPM | Supply Pricing Model (computer program) |
| SPOM | Surplus Power-Open Market |
| SS | Share-the-Savings Energy (rate) |
| TGT | Townsend-Garrison Transmission (rate) |
| UFT | Use of Facilities Transmission (rate) |
| USBR | United States Bureau of Reclamation |
| VI | Variable Industrial Power (rate) |
| VOR | Value of Reserves |
| WNP | Washington Public Power Supply System (Nuclear) Project |
| WPPSS | Washington Public Power Supply System |
| WPRDS | Wholesale Power Rate Development Study |
| WSPP | Western Systems Power Pool |
| WSCC | Western Systems Coordinating Council |

# 1. INTRODUCTION

This study presents BPA's Marginal Cost Analysis (MCA) for its 1996 rate case. The MCA estimates the marginal cost to BPA of serving firm load by month, day, and hourly period. Marginal cost is the additional cost a firm must incur to sell an additional unit of its product or service. This is equal to the direct cost of additional production or the revenue foregone by not selling an existing unit to a customer other than the one who actually buys it, whichever is less. Therefore, estimates of marginal costs are also estimates of the market prices for those products and services. The marginal cost estimates presented here are used to develop seasonal and diurnal shapes for BPA rates. The estimated marginal costs presented here represent the marginal cost BPA faces as a participant in an active, West Coast-wide wholesale power market.

The MCA employs the Power Market Decision Analysis Model (PMDAM) as its primary tool for estimating marginal costs. PMDAM simulates wholesale power market activity throughout the interconnected West Coast system. Additional information on costs of generating resources has also been used to supplement the output of PMDAM.

Section 2 explains the purpose of applying information about marginal costs to rate design. Section 3 explains the choice to consider the effects of the entire West Coast market on BPA's marginal costs, discusses how the approach to estimating them employs PMDAM, and precisely defines the products whose marginal costs are being estimated. Section 4 describes how PMDAM output is interpreted and applied to produce hourly and seasonally differentiated marginal costs of firm energy and demand. The Documentation for the MCA contains supporting data for further quantitative and analytical detail. See Documentation for the Marginal Cost Analysis Study, WP-96-FS-BPA-04A.

## 2. PURPOSE OF THE MARGINAL COST ANALYSIS

The purpose of the MCA is to inform rate design. In theory, incorporating information about marginal costs in rate design can promote economically efficient behavior. Welfare economics is the study of changes in human welfare caused by changes in the prices and quantities of goods and services produced, and one widely accepted conclusion among economists is that resource allocation is most efficient when all goods and services are priced at marginal cost. When a firm sells a unit of its product at its marginal cost, the additional revenue from the sale fully covers the cost the firm incurs to produce the product and make the sale, leaving the firm financially whole. When a firm sells its product at less than its marginal cost, the additional cost exceeds the additional revenue, and the difference represents a financial burden to the firm which cannot be sustained indefinitely.

Ideally, then, a firm will set its prices at marginal cost. A firm setting its prices equal to marginal cost provides an appropriate incentive to customers for seeking alternatives to the firm's product. The incentive is appropriate because the price the customer faces will just cover the cost of the resources necessary to produce the product. If the customer has a cheaper alternative, pricing the product at its marginal cost will allow the firm to avoid incurring additional costs for output which its customers could obtain elsewhere for less and will lead to an efficient allocation of society's scarce resources. Therefore, to the extent that BPA can incorporate information about its marginal costs into its rate-designs, BPA will provide information and incentive to customers that will help both conduct business in a more economically efficient manner.

## 3. APPROACH TO THE ESTIMATION OF MARGINAL COSTS

### 3.1 Use of West Coast Market

This study estimates the additional cost to BPA of meeting additional units of load, recognizing that BPA is an active participant in the West Coast wholesale power market. BPA can serve load at the margin either by acquiring new sources of generation or by purchasing in the interconnected West Coast market. BPA's options for purchase and sale on both a spot and contract basis extend to utilities throughout the interconnected West Coast system. BPA's reliance on purchases from utilities outside the Northwest has increased in recent years and will probably continue to do so. Purchases, sales, and exchanges with West Coast utilities represent BPA's alternatives to acquiring specific resources. These options, therefore, affect BPA's marginal costs. Accordingly, the wholesale power market to consider when estimating BPA's marginal costs is the entire interconnected West Coast system, from British Columbia to Southern California and the Inland Southwest.

## 3.2 The Power Market Decision Analysis Model (PMDAM)

The Power Market Decision Analysis Model (PMDAM) is an economic equilibrium model that simulates the operation of the West Coast bulk power market. The model simulates how the individual utilities in the system will expand and operate their own resources, and purchase and sell in the market in order to serve their individual needs at least cost. The model derives a least cost hourly operation for each major utility in the West Coast system (smaller utilities are grouped together to reduce complexity). PMDAM simulates not only hourly and monthly purchases and sales, but also resource development and longer term (in this study, five years) contracting for each utility or group of utilities. The model simulates market activity under different fuel prices and water conditions in order to account for uncertainty in these key variables.

The interconnections in the West Coast bulk power market are illustrated in Figure 1. The supporting database, shown in Section VII of the Documentation to the Marginal Cost Analysis (WP-96-FS-BPA-04A), describes the power systems of thirteen distinct parties (some of which are groups of smaller utilities) located in the five geographic regions represented by the solid dots. The sizes of the dots represents the relative sizes of the loads in the five regions.

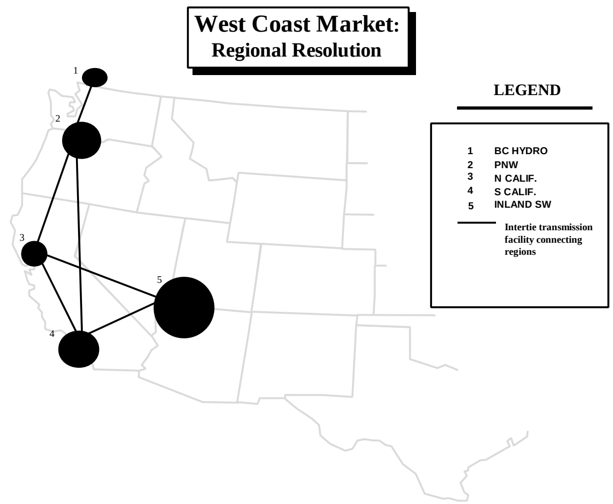


**Figure 1**

3.3 <u>Defining "Load"</u>

Marginal cost for an electric utility is the added cost of meeting an additional unit of load. In making decisions on how it will reliably meet additional load, a utility takes into account a number attributes or aspects of load. For this study, "load" is defined in terms of energy, firmness of energy, capacity, and demand:

1. <u>Energy</u>. "Energy" means kilowatt hours actually produced by BPA during any given hour. To meet energy load is to produce that amount of energy in any given hour. The marginal cost of energy is the added cost of producing an additional kilowatt-hour in any given hour.

2. <u>Firmness of Energy</u>. "Firmness of energy" means energy which a utility must be prepared to produce over the course of a month. The cost of firmness of energy does not include the cost of

the energy, only the cost of preparing to produce the energy sometime during the month. To meet firmness of energy load, a utility must have access to sufficient generating and contracting capability to insure the production of this amount of energy. The marginal cost of firmness of energy is the cost of preparing to produce an additional kilowatt-hour of energy some time during the month.

3. Capacity. "Capacity" means the maximum number of kilowatt-hours a utility must be prepared to produce within the heavy load hours during each week of a given month. To meet capacity load, a utility must have access to sufficient generating and contracting capability to insure that it can produce this many kilowatt-hours within the heavy load hours of the month. The marginal cost of capacity is the cost of preparing to produce an additional kilowatt-hour within the heavy load hours.

4. Demand. "Demand" means a number of kilowatt hours which a utility must be prepared to produce during the hour of its monthly peak energy load. To meet demand load a utility must have access to sufficient generating and contracting capability to insure that it can produce this number of kilowatt hours during the peak hour. The marginal cost of demand is the cost of being prepared to produce an additional kilowatt-hour on the hour of the monthly peak.

The difference between capacity and demand, as defined in the MCA, is the difference between being prepared to meet sustained and instantaneous peaks. "Capacity," for BPA, is defined as a preparedness to produce energy within a 96-hour per week heavy load hour period. In the MCA, "demand" is the preparedness to produce energy at the hour of BPA's peak load during the month.

3.4 <u>The Marginal Cost of Meeting Load, By Component</u>

The components of load are joint products; taking action to meet one component of load will often help to meet the others as well. The problem arises, then, of how to distribute the costs of the actions taken among the components of load, or how to cost the joint products. The solution used by PMDAM is to find the combination of actions with their associated costs that minimizes each utility's cost of meeting load. There is only one set of marginal costs that allows each utility to meet its load obligations at least cost. The mathematics and programming techniques used to find this solution are described in Section VIII of the Documentation to the Marginal Cost Analysis, WP-96-FS-BPA-04A.

In PMDAM, utilities meet load by: (1) Operating existing resources; (2) securing the right to the output of specific resources; this can mean contracting for the output of resources, as BPA does, or the direct ownership of resources common to most utilities; (3) contracting to buy or sell rights to energy with other utilities in the form of system sales; and (4) making spot sales to or purchases from other utilities.

3.5 Specifying the Inputs, Assumptions, And Output of PMDAM

1. Inputs. The inputs to PMDAM include all existing resources and contracts for all West coast utilities, existing interregional transmission capacity, load forecasts, supply curves of available new resources, generic types of possible new contracts, fuel prices, and water conditions. The load forecast for BPA in PMDAM consists of amounts of energy, firmness of energy, and capacity needed to meet BPA's obligations. The supply curves of new resources specify amounts of new generating and conservation resources available at various cost levels. The cost of conservation resources is based on capital costs only, since these resources typically have few, if any, operating costs. The cost of new generating resources consists of both capital costs and operating costs. Utilities select resources from these supply curves to add to the set of resources within their control. All resources are defined in terms of their ability to provide firmness of energy, capacity, and energy, and in terms of their capital and operating costs. The generic contracts include terms defined by their ability to provide firmness of energy, capacity, and energy. These and other input data used in this analysis appear in Section VII of the Documentation to the Marginal Cost Analysis, WP-96-FS-BPA-04A.

2. Output. The estimated marginal costs in this study are based on a single run of PMDAM. The run covers 5 calendar years (1996-2001). The run produces annual marginal costs of firmness of energy for each of the 5 years; monthly marginal capacity costs for each of the 12 months in each of the 5 years; and marginal energy costs for each hour of a typical Sunday, weekday, and Saturday of each month of each year. The output reported represents an average of marginal costs using 50 different, randomly-selected combinations of water conditions, forecasted fuel prices, weather conditions, and forced outages of thermal generating plants. The marginal energy costs from PMDAM appear in Table 1. The annual marginal costs of firmness of energy from

PMDAM appear in Table 2, column N. The monthly marginal costs of capacity from PMDAM appear in Table 3, columns B through M, lines 3 through 8.

## 4. HOURLY AND SEASONALLY DIFFERENTIATED MARGINAL COSTS OF FIRM ENERGY AND DEMAND

Marginal costs of firm energy by heavy-load hours, light-load hours, and season, and an annual marginal cost of demand, appear in Table 14. “Firm energy” is the combination of firmness of energy, energy, and, during heavy load hours, capacity. The marginal costs of firm energy in Table 14 are based on the PMDAM output described in Section 3.5, but several analytical steps were required to get from there to the results in Table 14.

PMDAM produced output for all five years of the rate-period, but BPA is developing its rates so that they are the same in each year of the test period. So that the marginal cost results were consistent with the development of BPA’s rates, the model’s output was levelized back to 1995 dollars.

PMDAM produced marginal energy costs for each hour of a typical weekday, Saturday, and Sunday, but, given the similarity of marginal energy costs in many of the hours, the results were used to divide the week into only two periods (heavy and light load hours). These two weekly periods were sufficient to separate hours with relatively high marginal costs of energy from hours with relatively low marginal costs of energy, and the costs for the various hours within each of the two periods were averaged together.

PMDAM produced marginal costs of firmness of energy on an annual basis, but these costs also vary from month to month, so PMDAM input and output data were used to distribute the annual marginal costs of firmness of energy across the various months of the year.

PMDAM produced marginal costs for sustained, 50-hour peaking capacity by month. These data were adjusted to conform to the 96-hour per week heavy load hour period. They were also adjusted to compensate for actual capacity returns to BPA’s systems that differ from the assumption used in PMDAM. In this latter adjustment, marginal costs were re-distributed between the southern intertie and BPA generating capacity. To arrive at monthly, marginal costs of firm energy, the marginal costs of 96-hour capacity were assigned only to heavy load hours, whereas the marginal cost of energy and firmness of energy were assigned to both heavy and light load hours, for each month.

The months were then grouped into seasons.

PMDAM was not used by itself to estimate a marginal cost of demand for BPA for purposes of this study. The marginal cost of demand is estimated as the ratio of the capital costs of a single-cycle combustion turbine to the those of a combined-cycle combustion turbine, times the marginal cost of 96-hour capacity from PMDAM.

From the PMDAM output described in Section 3.5, the following steps are taken to derive the marginal costs of firm energy by heavy load hours (HLH’s), light load hours (LLH’s), and seasons, and the annual marginal cost of demand shown in Table 14: (1) The annual marginal cost of firmness of energy from PMDAM is distributed into months; (2) all 5-year cost-streams are levelized to fiscal year (FY) 1996; (3) heavy load hours and light load hours of the week are identified; (4) marginal capacity costs are adjusted with reference to marginal costs of interregional transmission capacity; (5) the marginal cost of 50-hour capacity from PMDAM is converted to a marginal cost of 96-hour capacity corresponding to the number of heavy load hours in the week; (6) the marginal cost of demand is estimated with reference to the capital costs of combustion turbines; (7) marginal costs of energy, firmness of energy, and capacity are combined to get marginal costs of firm energy; (8) seasons are identified based on the marginal cost of firm energy; and (9) firm energy costs are combined into seasons. This methodology is described more fully below.

### 4.1 Distribution of The Marginal Cost of Firmness of Energy to Months

The annual marginal cost of firmness of energy from PMDAM is shaped monthly in proportion to the ratio of the demand for firm energy from BPA to natural hydro inflows (water flowing or falling into reservoirs other than that which has previously passed through a dam). This ratio balances demand and supply considerations that affect the marginal cost of firmness of energy to BPA. A high value for this ratio indicates a month when demand for energy is high relative to BPA's supply, so that the marginal cost of being prepared to produce energy is high during such a month relative to a month when this ratio is low.

Calculation of monthly marginal costs of firmness of energy is shown in Table 2. Column N of that table shows the annual marginal cost of firmness of energy from PMDAM. Lines 14-19 contain monthly ratios of BPA's demand for firm energy to the natural flows into the hydrosystem used in PMDAM. Like the marginal cost numbers, the ratios of demand for firm energy to hydro inflows in lines 14-19 represent averages over 50 different sets of conditions, each with different water conditions, fuel prices, weather, and forced outages of thermal generating plants. The load and inflow data themselves appear in Appendix A.

### 4.2 Levelizing 5-Year Cost Streams To FY 1996

The expected marginal costs of energy, firmness of energy, and capacity from PMDAM are levelized to FY 1996 and expressed in 1995 dollars. Levelized marginal costs represent weighted averages of the marginal costs in each of the future years. The weights used in taking this weighted average are determined using a real discount rate of 4.75%, with earlier years receiving higher weight.

### 4.3 Identifying Heavy And Light Load Hours of The Week

Heavy- and light-load hours of the week are identified by grouping together hours of the week with similar marginal costs of energy. Hours with high marginal costs are assigned to a group called heavy load hours, and hours with low marginal costs are assigned to a group called light load hours. The levelized marginal energy costs by hour of the week range from 12.4 mills/kWh at midnight on Sunday to 14.0 mills/kWh between 8:00 AM and 10:00 AM on weekdays and appear in lines 13, 28, and 43 of Table 5. These data represent annual averages. The load data used to weight the months in calculating them appear in Table 6. See the footnote to Table 5 for a description of the calculation.

The levelized annual marginal costs of energy for each hour of the typical week are separated into costing time periods using a cluster analysis. “Cluster analysis” is a statistical technique for grouping similar items together while separating the dissimilar. This cluster analysis groups hours by marginal cost of energy so that hours with similar marginal costs fall into the same cluster, while hours falling into different clusters are likely to have significantly different marginal costs. The cluster analysis divides annual average marginal costs of energy for each hour of the week, shown in Table 5, lines 13, 28, and 43, into two clusters.

Ideally, prices would change continually to track continual changes in marginal costs, but administration of continually changing rates is impractical for BPA.  The number of time periods should be enough to track significant cost variation while being practical to administer. Furthermore, the amount of hourly variation in marginal energy costs is minimal.  As a result, no more than two hourly costing/pricing periods within a week were considered in this analysis: hours with relatively high marginal costs and hours with relatively low marginal costs.

The cluster analysis and its results appear in Tables 8 and 9, respectively.  The hours of the week are ranked in descending order by marginal cost of energy in Table 8.  The parameter used to determine where to divide marginal costs into clusters is called a "pseudo F-statistic."  The pseudo F-statistic measures total variation in the set of marginal costs relative to total variation in marginal costs within the clusters.  The point where the two clusters are divided between relatively high and low marginal costs of energy, defined by the maximum of the pseudo F-statistics, appears in Table 8, column I.

The results of the cluster analysis appear in Table 9, where an "L" designates an hour as a member of the cluster with relatively low marginal costs of energy and an "H" as a member of the cluster with relatively high marginal costs of energy.  Section II of the Documentation to the Marginal Costs Analysis (WP-96-E-BPA-04A) discusses the cluster analysis in greater detail.

Based primarily on the results of the cluster analysis, heavy-load hours are defined as 6 a.m. to 10 p.m., Monday through Saturday, and light-load hours as the remaining hours of the week. Although the cluster analysis grouped the hour from 6 a.m. to 7 a.m. on Saturday the lower group, this hour was assigned to the higher group so that heavy and light load hours would be the same every day, Monday through Saturday, to help make rates simpler to administer.

Although the cluster analysis grouped several hours on Sunday in the higher group, all of Sunday was assigned to the light load hours. The results of the cluster analysis indicate that the marginal costs of energy during many hours on Sunday, while similar to hours of the week with relatively high marginal costs, are very close to marginal costs of energy during hours with relatively low marginal costs. Moreover, the marginal costs from PMDAM do not fully account for the amount of energy returned to BPA's system on Sundays under certain large capacity contracts. PMDAM models all capacity contracts as having 24-hour return of energy, as a simplification. However, BPA has actual capacity contracts, such as that with PP&L, with the option of 7-day return, which may be exercised on Sunday. The additional energy being brought onto BPA's system on Sunday would tend to drive the marginal cost of energy on Sunday lower, toward or into the light load hour group. Therefore, all hours on Sunday are included among the light load hours. An example of data on the operation of the PP&L contract appears in Section III of the MCA Documentation, WP-96-FS-BPA-04A.

### 4.4 The Marginal Cost of Capacity

Two steps are taken to get from the marginal cost of 50-hour per week capacity from PMDAM to the marginal cost of 96-hour per week capacity used in the marginal cost of firm energy. First, the capacity values from PMDAM are adjusted to reflect part of the marginal cost of Southern Intertie during summer months. This adjustment has the effect of re-shaping the marginal cost of capacity within the May-September period without changing the overall level of the marginal cost of capacity for that period. The adjustment produces estimates of marginal costs of capacity that track the shape of the California/Southwest loads which drive the marginal cost of capacity for all West Coast utilities, including BPA, during the summer months. Although neither the generation nor transmission capacity data alone reflect the contour of the California/Southwest loads, the sum of the two costs does.

The capacity adjustment adds the marginal cost of the Southern Intertie to BPA's marginal cost of generating capacity for the months of May-September. The resulting sum for each month is then scaled down to be consistent with the average level of the marginal cost of generating capacity for the five months; the sum of the marginal capacity costs for BPA generation and the Southern Intertie for each month is multiplied by the five-month average marginal cost of generating capacity and divided by the five-month average of the sums of generating capacity and Southern Intertie costs. The monthly sums appear in Table 3, lines 23-28. The scaled-down values appear in lines 32-37. Levelized marginal costs (line 38) vary between $0.01/kW/mo in April to $1.27/kW/mo in August.

Second, the marginal costs of 50-hour capacity from PMDAM are converted to marginal costs of 96-hour capacity. The number of heavy load hours in a week is 96. Accordingly, the appropriate number of hours per week to use in defining "capacity" for the MCA is 96 as well. See Table 3, Lines 43-46. The conversion is performed by multiplying the marginal cost of 50-hour capacity by an adjustment factor, described in the footnote to Table 3, line 44.

4.5 <u>The Marginal Cost of Demand</u>

The marginal cost of demand is estimated to be $0.37/kW/mo. The estimate is derived by multiplying the marginal cost of 96-hour capacity by the ratio of the capital cost of a single-cycle combustion turbine ($307/kW, shown in Table 3, line 47) to those of a combined-cycle combustion turbine ($460/kW; Table 3, line 48). A single-cycle combustion turbine is suitable for providing additional units of demand because of its low capital costs, while the higher capital costs of a combined-cycle machine, offset by its lower operating costs, make it suitable for providing additional 96-hour peaking capacity. In a market in which additions of capacity kept pace with load growth, the capital costs of a single-cycle combustion turbine (SCCT), which normally runs at about a 10% plant factor, would represent a good proxy for the marginal cost of demand. The capital costs of a "baseload" combined-cycle combustion turbine (CCCT), which normally runs at about a 65% plant factor, would represent a good proxy for the marginal cost of sustained, 96-hour per week peaking capacity.

Under surplus conditions like those currently expected during the five-year rate period, the costs of these sources of generating capacity exceed the capacity's market value. As such, the costs of these resources are not used to establish the level of the estimated marginal cost of demand. For purposes of this analysis, the relationship between the capital cost of a SCCT and a CCCT is assumed to be the same as the relationship between the marginal cost of demand and the marginal cost of sustained peaking capacity under expected market conditions. Therefore, the ratio of the capital costs of a SCCT to those of a CCCT is multiplied by the marginal cost of sustained peaking capacity from PMDAM in line 46 of Table 3 to arrive at the marginal cost of demand in line 49.

The monthly marginal costs of demand, in 1995 dollars, range from $0.01/kW/mo in April to $1.18/kW/mo in August. They average $0.35/kW/mo on an annual basis. The costs of combustion turbines come from an update to the 1993 Technical Assessment Guide published by the Electric Power Research Institute (EPRI). These costs appear in Table 3, lines 47 and 48. Excerpts from the EPRI TAG and the updated data on CT costs appear in of the Documentation for the Marginal Cost Analysis, WP-96-FS-BPA-04A, Section IV.

BPA's rate design requires information about nominal marginal costs of demand. Since $0.35/kW/mo represents a real levelized value in 1995 dollars, an inflation component is added to that figure to get the nominal annual marginal cost of demand of $0.37/kW/mo, shown in Table 4, line 8.

### 4.6 Combining the Marginal Costs Components of Firm Energy

The marginal cost of firm energy during heavy load hours is the sum of marginal costs of heavy load hour energy, capacity, and firmness of energy. The marginal cost of firm energy during light load hours is the sum of the marginal costs of light load hour energy and firmness of energy. Levelized marginal costs of firm energy by hourly period and month range from 8.8 to 19.1 mills/kWh during heavy load hours and 7.6 to 18.0 mills/kWh during light load hours. The heavy load hour annual average is 16.3 mills/kWh, and the light load hour annual average is 15.0 mills/kWh. See Table 10, Columns G and H, respectively.

### 4.7 Identification of Seasons

Seasons are defined as September-December, January-March, April, May-June, July, and August, based on the heavy load hour and light load hour marginal costs of firm energy for each month described in Section 4.6. The seasons are defined (1) so that months within seasons are contiguous, and (2) to limit the difference between monthly marginal costs of heavy load hour (light load hour) firm energy and seasonal average marginal costs of heavy load hour (light load hour) firm energy to one mill or less, though not necessarily to minimize these differences . The first criterion, contiguous seasons, addresses concern for administrative simplicity. The second criterion, one mill difference between the monthly and seasonal average, addresses the need for rates to track marginal costs closely across months. At least six seasons are required to satisfy both of the above criteria.

If the six seasons were selected only to minimize the differences between the monthly and seasonal average marginal costs, the seasons would not be contiguous. Non-contiguous seasons would be difficult to administer for both BPA and its customers. However, the non-contiguous seasons selected based solely on minimizing differences between the monthly and seasonal average marginal costs provide a "benchmark" to measure how closely the proposed seasons allow rates to track BPA's marginal costs. Table 13 presents a comparison between the differences between monthly and seasonal marginal costs for the proposed seasons and for the set of six non-contiguous seasons which would minimize the differences, but not be contiguous. Column H gives the total of these differences and the ratio between the totals for the two sets of seasons. The total of the differences for the proposed, contiguous seasons are 14 percent greater than those for the non-contiguous seasons which minimize the differences. Consequently, the contiguous seasons selected for administrative simplicity still closely track BPA's marginal costs.

### 4.8 Hourly- And Seasonally-Differentiated Marginal Costs of Firm Energy and Demand

Levelized marginal costs for the 1997-2001 rate period appear in Table 14. The marginal costs of firm energy are expressed in 1995 dollars and range from 8.0 mills/kWh in the light load hours of May to 19.0 mills/kWh during the heavy load hours of the winter season. The marginal cost of demand equals $0.37/kW/mo in nominal terms. Direct application of these marginal costs as rates for the products to which they apply, after adjusting them to account for general price inflation, without regard to revenue or repayment requirements, would provide customers with economic price signals indicating the cost of serving loads, encouraging customers to make efficient operational and investment decisions.