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(1) Energy Agency

(2A)* APPLICATION for CERTIFICATE OF NEED for LARGE HIGH VOLTAGE TRANSMISSION LINE and ASSOCIATED FACILITIES

(3) No date, received April 1978

(4) 34 p. + Exhibits ; ill., maps, stats.

(2D) **Submitted by**

Cooperative Power Association

and

United Power Association

resources

STATE OF MINNESOTA

Before the

MINNESOTA ENERGY AGENCY

In the Matter of the Application of	)
Cooperative Power Association and	)
United Power Association for a	)
Certificate of Need for Large High	)
Voltage Transmission Line and	)
Associated Facilities.	)

Cooperative Power Association (CPA), a Minnesota cooperative corporation, and United Power Association (UPA), a Minnesota cooperative corporation, pursuant to the provisions of Minn. Stats. 1974, Secs. 116H.01-.15, as amended (the Minnesota Energy Agency Act), hereby apply for a Certificate of Need for a Large High Voltage Transmission Line (LHVTL) consisting of three segments, to-wit: the Minnesota portion of a proposed Coal Creek (North Dakota)-Dickinson (Minnesota) ±400 kilovolt (kV) direct current (dc) electric transmission line; a proposed Dickinson-Coon Creek (Minnesota) 345 kV alternating current (ac) double circuit electric transmission line; and a proposed Dickinson-Wilmarth (Minnesota) 345 kV ac single circuit electric transmission line; and associated facilities. CPA will own a

56/100ths interest and UPA a 44/100ths interest in said proposed transmission line and associated facilities.

The Minnesota portion of the Coal Creek-Dickinson segment of the proposed LHVTL will operate at a nominal voltage of $\pm$400 kV dc and will be approximately 164 miles in length. The Dickinson-Coon Creek segment will operate at a nominal voltage of 345 kV ac and will be approximately 28 miles in length. The Dickinson-Wilmarth segment will operate at a nominal voltage of 345 kV ac and will be approximately 75 miles in length.

The fee required by Minn. Reg. EA 621 (c)(2) for processing this application is $26,000.00; a check for 25 percent of the fee accompanies this application.

Correspondence and other communications concerning this application should be addressed to:

James L. Herbert
Manager of Planning and Engineering
Cooperative Power Association
6600 France Avenue South
Minneapolis, Minnesota 55435
Telephone: (612) 925-4556

Copies of all correspondence concerning this application should be sent to:

David H. Kopecky
Special Assistant to the General Manager
United Power Association
Elk River, Minnesota 55330
Telephone: (612) 441-3121

Dated this 6th day of October, 1975.

James L. Herbert

James L. Herbert
Manager of Planning and Engineering
Cooperative Power Association

David H Kopecky

David H. Kopecky
Special Assistant to the General
Manager, United Power Association

STATE OF MINNESOTA)
) SS.
COUNTY OF ANOKA)

AFFIDAVIT

Philip O. Martin, being first duly sworn, deposes and says that he is the General Manager of United Power Association (UPA), a Minnesota cooperative corporation, Elk River, Minnesota 55330; that UPA owns a 44/100ths interest in the LHVTL and associated facilities which are the subject of the within application for a Certificate of Need; that Cooperative Power Association (CPA), a Minnesota cooperative corporation, 6600 France Avenue South, Minneapolis, Minnesota 55435, owns a 56/100ths interest in said LHVTL and associated facilities; that James L. Herbert, Manager of Planning and Engineering for CPA, is authorized to act on behalf of UPA with respect to said application; further affiant saith not, save and except that this affidavit is made in support of the within application.

Philip O. Martin

Subscribed and sworn to before me
this 3rd day of October, 1975.

Kenneth J. Wahl
Notary Public
Anoka County, Minnesota

KENNETH J. WAHL
NOTARY PUBLIC - MINNESOTA
ANOKA COUNTY
My Commission Expires Sept. 9, 1977

STATE OF MINNESOTA)
) SS.
COUNTY OF HENNEPIN)

AFFIDAVIT

T. V. Lennick, being first duly sworn, deposes and says that he is the General Manager of Cooperative Power Association (CPA), a Minnesota cooperative corporation, 6600 France Avenue South, Minneapolis, Minnesota 55435; that CPA owns a 56/100ths interest in the LHVTL and associated facilities which are the subject of the within application for a Certificate of Need; that United Power Association (UPA), a Minnesota cooperative corporation, Elk River, Minnesota 55330, owns a 44/100ths interest in said LHVTL and associated facilities; that James L. Herbert, Manager of Planning and Engineering for CPA, is authorized to make said application and to act on behalf of CPA with respect to said application; further affiant saith not, save and except that this affidavit is made in support of the within application.

T V Lennick

T. V. Lennick

Subscribed and sworn to before me
this 3rd day of October, 1975.

John E. Drawz

John E. Drawz
Notary Public
Hennepin County, Minnesota

JOHN E. DRAWZ
NOTARY PUBLIC-MINNESOTA
HENNEPIN COUNTY
My Commission Expires Sept. 7, 1977

STATE OF MINNESOTA)
) SS. VERIFICATION
COUNTY OF HENNEPIN)

James L. Herbert, being first duly sworn, deposes and says that he is the Manager of Planning and Engineering for Cooperative Power Association (CPA); that in the course of his duties, he has caused the within application for Certificate of Need to be made; that he has carefully read said Application; that the facts contained therein are true to his own knowledge, or, if not of his own knowledge, they are true to the best of his information and belief and that he has reason to believe and does believe them to be true.

James L. Herbert

James L. Herbert

Subscribed and sworn to before me
this 3rd day of October, 1975.

John E. Drawz

John E. Drawz
Notary Public
Hennepin County, Minnesota

JOHN E. DRAWZ
NOTARY PUBLIC-MINNESOTA
HENNEPIN COUNTY
My Commission Expires Sept. 7, 1977

STATE OF MINNESOTA)
) SS. VERIFICATION
COUNTY OF ANOKA)

David H. Kopecky, being first duly sworn, deposes and says that he is the Special Assistant to the General Manager of United Power Association (UPA); that in the course of his duties he has prepared or caused to be prepared information for inclusion in the within Application for Certificate of Need; that he has carefully read said Application; that the facts contained therein are true to his own knowledge, or if not of his own knowledge, they are true to the best of his information and belief and that he has reason to believe and does believe them to be true.

David H. Kopecky

Subscribed and sworn to before me
this 3rd day of October, 1975.

Kenneth J. Wahl
Notary Public
Anoka County, Minnesota

KENNETH J. WAHL
NOTARY PUBLIC - MINNESOTA
ANOKA COUNTY
My Commission Expires Sept. 9, 1977

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I. Introduction.

Cooperative Power Association (CPA) is a cooperative corporation under the laws of the State of Minnesota with its corporate headquarters at 6600 France Avenue South, Minneapolis, Minnesota. United Power Association (UPA) is a cooperative corporation under the laws of the State of Minnesota with its corporate headquarters at Elk River, Minnesota.

The business of both CPA and UPA is to provide and supply the electric power and energy requirements of their respective member distribution cooperatives, which in turn distribute the power and energy to the ultimate consumers in their respective rural service areas. CPA and UPA are generally referred to in the utility industry as generation and transmission cooperatives. CPA has 19 member distribution cooperatives which serve approximately 121,000 accounts in 48 counties in west central and southern Minnesota. UPA has 14 member distribution cooperatives which serve approximately 138,000 accounts in 29 counties in central, north central and east central Minnesota and 4 counties in Wisconsin.

In order to provide a reliable supply of electric energy to meet the future requirements and needs of the ultimate consumers served by their member distribution cooperatives, CPA and UPA in 1973, after a thorough study and consideration of feasibility reports and related information and data, entered into an agreement to construct and operate an electric generation and transmission project which is sometimes referred to as the "CU Project". The project consists generally of a 1,000 megawatt fossil fuel generating plant (Coal Creek Station) currently under construction near Underwood, North Dakota. The energy generated at the Coal Creek Station will be transmitted by a $\pm$400 kV dc transmission line from the Coal Creek Station to a conversion facility (Dickinson Substation) located near Delano, Minnesota. The energy will then be delivered into an existing grid of HVTLs by a 345 kV ac double circuit transmission line from the Dickinson Substation to the NSP Coon Creek Substation located in Coon Rapids, Minnesota, and by a 345 kV ac transmission line from the Dickinson Substation to a proposed NSP Wilmarth Substation located near Mankato, Minnesota. The energy will be delivered from the Coon Creek and Wilmarth Substations by the CPA and UPA transmission and distribution systems to their member cooperatives.

A portion of the CU Project is the subject of this application, namely: that part of the $\pm$ 400 kV dc transmission line located in Minnesota; the 345 kV ac double circuit transmission line from the Dickinson Substation to the Coon Creek Substation; and the 345 kV ac single circuit transmission line from the Dickinson Substation to the Wilmarth Substation, and associated facilities.

II. Need Summary [EA 632].

CPA, through it member distribution cooperatives, serves approximately 121,000 accounts. Its service area is located in west central and southern Minnesota and is graphically shown on Exhibit 2. The CPA load is primarily rural, consisting of farms, rural urban areas, commercial and light industrial. This load is influenced by the season, weather conditions, temperature, and time of day. Its load is a winter peaking load.

The CPA system consists of bulk power substations and transmission lines with voltages from 34.5 kV to 230 kV. These facilities are interconnected with several other utilities in southern, western and northern Minnesota to form a coordinated system to provide a reliable and economic supply of electric energy to the ultimate consumers.

In the past, CPA has supplied its loads from a combination of purchases from MAPP members, purchases from the United States Bureau of Reclamation (USBR), and by sharing with Dairyland Power Cooperative the output of the Genoa No. 3 generating unit located near Genoa, Wisconsin. The CPA share of this unit will be 170 megawatts (MW) after 1975. CPA also has 11 MW of diesel capacity located at Benson and Jackson, Minnesota.

A significant part of CPA member system requirements through

1977 will be obtained from the USBR. However, because of the USBR's obligation to its custmers, who receive all their requirements from the USBR, considerably less short term power will be available to CPA from USBR. In fact, in 1977, CPA will receive 214 MW less from the USBR than it did in 1976.

CPA forecasts a continuing increase in its system power requirements. In 1974 CPA's customer energy requirements were 1623 gigawatt hours (GWH). In 1978 this requirement is projected to be 2374 GWH, in 1979, 2579 GWH, and in 1990, this requirement is projected to be 6780 GWH. In 1974, CPA's demand obligation (demand plus reserves) was 429 MW. In 1978 this requirement is projected to be 645 MW, in 1979 700 MW, and in 1990, this requirement is projected to be 1841 MW. The generation capacity of the CPA system shows a deficit in the winter of 1978 of 332 MW and in the winter of 1979 of 387 MW. The Coal Creek Station, with the first 500 MW unit scheduled to go into commercial operation in the fall of 1978, will reduce this deficit to 77 MW, and the second unit in 1979 will produce a surplus of 119 MW in the winter of that year. However, in the winter of 1981 a deficit again appears.

UPA, through its member distribution cooperatives, serves approximately 138,000 accounts. Its service area is located in central, north central and east central Minnesota and a portion in northwest Wisconsin (Exhibit 3). Its load also is primarily rural consisting of farms, rural urban area, commercial and light industrial. Its load is a winter peaking load.

The UPA system consists of generation facilities having a combined generating capacity of 237 MW. These facilities consist of a fossil fuel generating station located at Stanton, North Dakota (166 MW), a generating station located at Elk River, Minnesota (50 MW), which uses petroleum products as its fuel, and six diesel generating plants in Minnesota (21 MW). In addition the system consists of substations and transmission lines which range from 22 kV to 230 kV. The UPA system is interconnected with other utilities.

UPA also forecasts a continuing increase in its system power requirements. In 1974 UPA's customer energy requirements were 1237 GWH. In 1978 this requirement is forecast to be 1918 GWH, in 1979 2099 GWH, and in 1990 the forecast is 6628 GWH. In 1974 UPA's system winter demand obligation was 350 MW. In 1978 the demand obligation is forecast to be 540 MW, in 1979 to be 615 MW, and in 1990 the demand obligation is forecast to be 1759 MW. The generation capacity of the UPA system shows a deficit in the winter of 1978 of 303 MW and in the winter of 1979 of 378 MW. The winter 1978 deficit will be reduced to 88 MW by the addition of the first unit of the Coal Creek Station. The second unit will take up the deficit in the winter of 1979. However, in the winter of 1980 a small deficit appears and continues to increase each year thereafter.

In the winter of 1978 CPA and UPA will have a combined deficit of 635 MW and in the winter of 1979 a combined deficit of 765 MW. In order to assure to their ultimate consumers an available and reliable supply of electric energy, CPA and UPA in 1973 entered into an agreement to construct the CU Project. Since that date engineering design, procurement, and actual construction have commenced to meet the on-line schedule of the first generating unit in the fall of 1978 and the second in 1979. The LHVTL is scheduled for fall 1978 to receive and transmit the energy from the first unit.

Subsequent to the initiation of the CU Project, the Minnesota Legislature enacted Laws 1974, C 307 (effective March 28, 1974) creating the Minnesota Energy Agency and providing for the requirement of a certificate of need before construction of certain types of projects in Minnesota, a portion of the CU Project being included within such requirement. In October 1975, rules of the Agency were promulgated relating to the contents of an application for certificate of need and the processing of such applications.

Various alternatives to the construction of the LHVTL have been considered, including a new fossil fuel generating plant in Minnesota, upgrading existing CPA/UPA transmission lines, and annual firm energy purchases from Mid-Continent Area Power Pool (MAPP) or others. However, none of these alternatives is available to meet the 1978-1979 system requirements of the applicants. A possible alternative which might meet this requirement schedule is the construction of base loaded gas turbine generators. However, because of the prohibition of the use of petroleum products for new generation by the national energy policy, this possible alternative must be rejected. Therefore, there are no available alternatives to the construction of the LHVTL for which application is made.

The situation which presents itself at the time of this application is this: the CU Project, which commenced in 1973, consists of a generating plant in North Dakota which is under actual construction, with the first 500 MW unit being scheduled for commercial operation in the fall of 1978 and the second 500 MW unit for fall 1979. The transmission lines to receive, transmit and deliver the energy from the plant are scheduled for operation by the fall of 1978. The need for the LHVTL is obvious. No alternatives to the LHVTL are available. Without the LHVTL, the large deficits in the system requirements of the applicants cannot be provided for, except by the completion of the CU Project as scheduled. The result of denial of a certificate of need would be an unacceptable level of reliability of electric service to the ultimate consumers of the applicants in Minnesota and neighboring states. The applicants' systems would also be denied the significant socially beneficial uses of the output of the CU Project.

FIGURE I

COMBINED DEMAND OBLIGATION AND GENERATION PLUS LONG TERM PURCHASED CAPACITY (WITH PROPOSED FACILITY)

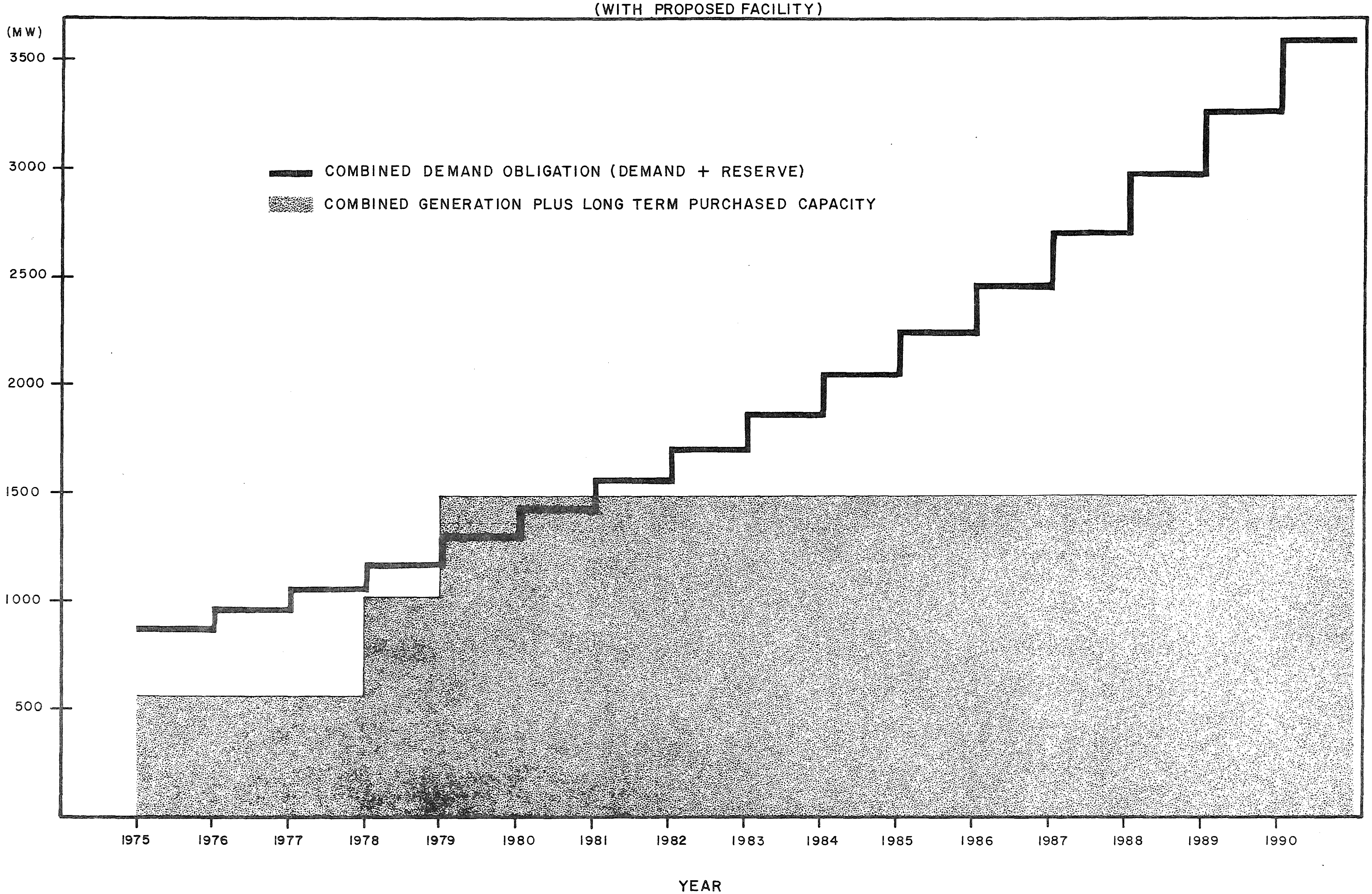


FIGURE 2

COMBINED DEMAND OBLIGATION AND GENERATION PLUS LONG TERM PURCHASED CAPACITY (WITH PROPOSED FACILITY)

Year	System Demand*	Demand Obligation**	Generation	Long Term Firm Purchased Capacity***
1975	773	889	423	135
1976	848	975	423	135
1977	931	1071	423	135
1978	1031	1186	893	135
1979	1144	1316	1359	135
1980	1250	1437	1359	135
1981	1366	1571	1359	135
1982	1494	1718	1359	135
1983	1635	1880	1359	135
1984	1790	2059	1359	135
1985	1962	2256	1359	135
1986	2152	2474	1359	135
1987	2361	2715	1359	135
1988	2593	2982	1359	135
1989	2847	3274	1359	135
1990	3131	3601	1359	135

* Taken from Line 1, Exhibit 29
** Demand obligation is system demand plus 15% reserve requirement
***CPA - 111 mw, UPA - 6 mw, plus 15% reserve requirement

All numbers are in megawatts

III. Description of Proposed LHVTL [EA 634].

A. Type and General Location [EA 634(a)].

1. The ±400 kV dc LHVTL will enter Minnesota from North Dakota in Traverse County and will run southeasterly to the Dickinson Substation near Delano, in Wright County, Minnesota.

a. Design voltage: ±400 kV dc bi-polar

b. Design power capability: 1000 megawatts (MW)

c. Expected losses at design voltage and current: 13.7 MW at Coal Creek dc terminal and 13.5 MW at Dickinson dc terminal; 38.9 MW line loss (Coal Creek-Dickinson)

d. Approximate length: 410 miles total, with approximately 164 miles in Minnesota

e. A map showing the location of the dc terminals is included herein as Exhibit 1

2. The 345 kV ac double circuit LHVTL will run from the Dickinson Substaton easterly to the NSP Coon Creek Substation in the City of Coon Rapids, Anoka County, Minnesota.

a. Design voltage: 345 kV ac

b. Design power capability: 1207 MVA per circuit

(thermal rating)

c. Expected losses:

(1). At design voltage and current: 19.3 MW per circuit

(2). At substation: nominal

d. Approximate length: 28 miles

e. A map showing the location of the substations is included herein as Exhibit 1

3. The 345 kV ac single circuit LHVTL will run from the Dickinson Substation southerly to the proposed NSP Wilmarth Substation near Mankato, Minnesota.

a. Design voltage: 345 kV ac

b. Design power capability: 1075 MVA (thermal rating)

c. Expected losses:

(1). At design voltage and current: 46.7 MW

(2). At substations: nominal

d. Approximate length: 75 miles

e. A map showing the location of the substations is included herein as Exhibit 1.

B. Availability of Alternatives to the LHVTL [EA 634(b)].

There are no alternatives to the construction of the LHVTL that could be constructed or utilized to supply the deficiencies in power in the CPA and UPA systems by 1978, when the first 500 MW unit at the Coal Creek Station is scheduled for commercial operation, or by 1979, when the second 500 MW unit is scheduled for commercial operation, to provide a reliable level of service to the ultimate consumers. In considering alternatives, the time element is of critical significance. The ±400 kV dc and 345 kV ac double circuit transmission lines must be ready to receive power from the first unit of the Coal Creek Station by the fall of 1978, and the 345 kV ac single circuit transmission line must be ready to receive power in 1979. As previously noted, the CU Project commenced in 1973, and it has progressed continuously since then with engineering, procurement, and actual construction of the Coal Creek Station. The availability of alternatives must of necessity, therefore, be considered in the framework of a project already under construction to meet a fall 1978 schedule.

Construction of a new fossil fuel generating plant in Minnesota is not an available alternative. It is the best estimate of the applicants that, if design engineering were to commence immediately, and if applications for the various required state permits were filed and processed as expeditiously as possible, such a plant could not be in commercial operation until 1983 or 1984. This would leave a period of at least five years during which the power requirements of their ultimate consumers could not be met by CPA and UPA.

Construction of base loaded gas turbine generators is not an available alternative. Gas turbine generators conceivably could be constructed to meet the 1978-1979 schedule. However, the national energy policy as reflected in the Federal Energy Administration Act of 1974 (Pub.L. 93-275) and the regulations 10 CFR 215.3 prohibit the use of petroleum products in new base loaded power generators. In addition, the cost of energy from such base loaded units would be prohibitive.

The applicants do not have existing transmission lines or existing generating facilities which could be upgraded as alternative to construction and use of the subject LHVTL.

Both CPA and UPA are members of MAPP. Capacity is not projected to be available in the MAPP Pool for firm purchases of energy over a long or even intermediate term. Some energy is available from the MAPP Pool on a seasonal basis but the amount so available is declining. The requirements of CPA and UPA are for firm energy, available on an annual basis, year after year, and such energy cannot be obtained from the MAPP Pool or from others. Therefore, purchase power is not an available alternative to provide the level of reliable energy required.

C. Maps of Applicants' Systems [EA 634(c)].

Maps showing the applicants' systems to be served by the proposed LHVTLs are included herein as Exhibits 2 and 3.

IV. Peak Demand and Annual Electrical Consumption Forecast [EA 635].

Minn. Reg. EA 635(a) provides in part as follows:

"Each appplication shall contain pertinent data concerning peak demand and annual electrical consumption within the applicant's service area and system * * *."

In the sections that follow, data pertaining to Annual Electrical Consumption Forecast and data relative to Demand and Load Factor are set forth and analyzed.

A. Annual Electrical Consumption Forecast [EA 635(b)(1) & (2)].

A portion of UPA's service area includes a small area of northwestern Wisconsin. UPA's annual electrical consumption by ultimate consumers within its Minnesota service area is found in Exhibit 4 [EA 635(b)(1)].

The annual electrical consumption data for each forecast year by ultimate consumers within the applicants' systems, for the categories listed in Minn. Reg. EA 635(b)(2), are found in Exhibit 5 (for CPA), Exhibit 6 (for UPA) and Exhibit 7 (Combined CPA/UPA).

B. Demand and Load Factor.

1. Estimate of Demand by Ultimate Consumers [EA 635(b)(3)].

The applicants do not have historical records of demand for power by ultimate consumers by category. For the purpose of this forecast, the demand estimate for each category was made using the historical proportion of energy usage attributable to each consumer category.

Exhibit 8 sets forth CPA's estimate of demand for power by ultimate consumers by category at the time of system peak demand.

Exhibit 9 sets forth UPA's estimate of demand for power by ultimate consumers by category at the time of system peak demand.

2. <u>System Peak Demand by Month</u> [EA 635(b)(4)].

An estimate of the system peak demand by month is found in Exhibit 10 (for CPA) and in Exhibit 11 (for UPA). The forecast data is based upon percentages derived from historical system peak demand data.

3. <u>Monthly Average System Daily Load Factor</u> [EA 635(b)(5)].

The monthly average system daily load factors were calculated from historical billing demand and energy data. An average of the historical monthly average system daily load factors was used for the projected years 1975 through 1990.

Exhibit 12 sets forth the CPA monthly average system daily load factor. Exhibit 13 sets forth the UPA monthly average system daily load factor.

4. Monthly Average System Weekday Load Factor [EA 635(b)(6)].

Exhibit 14 shows CPA's monthly average system weekday load factor and Exhibit 15 shows UPA's monthly average system weekday load factor.

5. Monthly Average System Weekend Load Factor [EA 635(b)(7)].

Exhibit 16 shows CPA's monthly average system weekend load factor and Exhibit 17 shows UPA's monthly average system weekend load factor.

C. Forecast Documentation [EA 635(c)].

1. Forecast Methodology [EA 635(c)(1)].

The demand and energy projections for this forecast were prepared in compliance with the Rural Electrification Administration (REA) forecasting procedures and were based on a mathematical trending of historical electrical consumption. The applicants and all other REA financed utilities must comply with these procedures as a condition precedent to receiving REA financing.

The demand and energy forecast, also termed a Power Requirements Study, has three major objectives. First, it attempts to identify the types and magnitudes of system loads. Second, it provides a breakdown of system energy consumption requirements. Third, it provides an estimated peak system demand for each forecast year.

The Power Requirements Study was developed in four steps:

(1). Development of Historical Load Growth Data.

The first step in the study was the development of historical load growth data. Using customer billing records and totals for demand and energy as metered at each system delivery point, the total annual energy consumption requirements of each member cooperative were classified for each year of the eleven year period previous to the current year.

(2). Trending of Historical Data Points.

Using logarithmic trending techniques, a growth curve was fitted to the annual energy consumption data points of each member system. Each growth curve was extrapolated fifteen years beyond the current year to provide an annual energy consumption forecast.

The logarithmic trending equation, which may be expressed as $Y = AB^x$, uses the following components:

Ep = antilog [A + (B times Xp)]

A = sum($\log_{10}(E_h)$)/N

B = sum(Xn times $\log_{10}(E_h)$)/sum(Xn^2)

$Y_d = Ep - E_h$

where:

Ep - projected annual energy consumption requirement (MWH) for each forecast year

E_h - annual energy consumption data point (MWH) for each year of the N year base period used in establishing a trend

N - total number of historical years used in establishing a trend

Xn - control variable which accounts for the timing of the historical data points range = $-(N - 1)/2$ to $+(n - 1)/2$

X_p - control variable which accounts for the timing of of the projected energy forecast

Y_d - variable which measures the fit of the trend to the historical data points

(3). <u>Calculation of Peak System Demand</u>.

From the energy consumption forecast and the average annual load factor of each member, a corresponding annual peak demand was calculated. The projected requirements for each member were then added by year, to provide an annual demand projection for the applicants' systems.

The Demand and Energy Relationship may be expressed by the formula: D = (E)/(T) times (LF) where:

D - hourly integrated peak system demand (MW)

E - annual energy consumption requirement (MWH)

T - hours per year (8760)

LF- average annual system load factor (decimal form)

(4). <u>Finalized Results</u>.

As a final step, the energy consumption forecast and detailed estimates of future system energy requirements, as provided by the applicants' member cooperatives, were used to divide the total projected annual system energy requirement into ultimate consumer categories.

The technique of exponential curve fitting to electricity sales history for the purpose of forecasts has provided reliable results. The applicants' service areas are predominantly rural, with low energy densities. The trending technique is very suitable to this type of service area because the service area has the ability to absorb greater amounts of electrical energy growth and will continue to have such a capacity throughout the forecast period.

The basic trending technique has a weakness in that it does not consider all the possible future influences on electric consumption growth, if those influences did not exist in the past. This generally results in a conservative forecast. For example, a large and rapid conversion from non-electrical to electrical heating will not be accounted for in a forecast based on trending. This type of occurrence will result in a forecast which underestimates electrical demand.

The data requirements are considerably less for the trending technique which uses historical sales that are readily available from consumer billing records. Because there is less data collection and less manpower and computer time involved in making forecast correlations, the cost to make a forecast based on trending is less than other techniques.

2. Data Base for Forecasts [EA 635(c)(2)].

The data base for the Power Requirements Study forecasts is the billing data of applicants' member cooperatives, which contain the history of the number of consumers and the average usage of electricity per consumer for the various billing classifications. Additionally, the purchased power and sales history for each cooperative is used to determine projected loss and load factor numbers.

Some minor adjustments were made to normalize the data so as to obtain a true growth rate. For example, in February, 1970, Nobles Cooperative became a member of CPA. Nobles' historical energy requirement, which amounted to 5% of the total CPA requirement, is included with the historical data for trending purposes. Likewise, Chandler Air Force Base, .5% of the total CPA requirement in 1970, and Wadena Air Base, .2% of the total CPA requiement in 1969, are not included because the air bases are no longer served.

3. Assumptions and Special Information [EA 635(c)(3)].

The fundamental assumption underlying the development of the Power Requirements Study was the premise that historical trends in system load growth are indicative of future load growth trends. The future growth rate for the overall system is expected to approximate historical trends for the previous seven to eleven year period. A second basic assumption is that the system load density was not saturated in the past, and is not expected to be saturated during the forecast period.

The applicants assumed that there would be no radical change in the availability of alternate sources of energy. However, a report entitled "Minnesota Energy Situation to 1985," issued by the Minnesota Energy Agency, indicates that oil and gas availability will level off or decrease. Electrical energy may have to take up more of the expected continued energy requirement. The applicants have completed a survey of some of their member cooperatives and they find that a greater percentage of new residences are installing electric heat than in the past. This would indicate that the applicants' load forecast would tend to be conservative.

The applicants did not assume any unusual load growth because of conversion from other fuels to electricity. The Minnesota Energy Agency report entitled "Minnesota's Energy Situation to 1985" predicts that use of gas as an energy source will decline. This will mean that some of the present users of gas will have to curtail use or convert to use of other fuels.

It is expected that curtailments will be more severe in the use of gas for generation of electricity and industrial uses than for residential use. Since the applicants do not have a large number of industrial consumers on their systems, they did not forecast any unusual load growth because of fuel conversion.

The applicants recognize that there will be appreciable increases in the future price of electricity. However, a large portion of the energy used by the applicents' consumers is for agricultural purposes. It is assumed that there will continue to be a growing need for food products. Therefore, the applicants assumed that there would not be unusual decreases in load growth because of the expected cost of electricity.

The applicants assumed that there are no existing conservation programs under federal or state legislation that would have an unusual effect on long term electrical demand forecasts.

4. Coordination of Forecasts with Other Systems [EA 635(c)(4)].

The applicants' load forecasts are coordinated with those of the other MAPP participants as well as with the other members of the Minnesota/Wisconsin Power Suppliers Group. The applicants provide copies of their load forecasts to the MAPP Coordination

Center which compiles this information into coordinated overall forecasts for the MAPP region. The applicants also exchange load forecasts with other members of the Minnesota/Wisconsin Power Suppliers Group. A committee of the group coordinates this data for use for informational and planning purposes.

V. System Capacity [EA 636].

In order to maintain an adequate level of service to its accounts, CPA must procure additional generating capacity. As indicated in Section IV (EA 635) and Exhibit 27, CPA will have an estimated seasonal system demand of 561 MW in winter of 1978. The system will also have a corresponding reserve obligation of 68 MW and a total firm capacity obligation of 518 MW. Even with the addition of 255 MW from the first Coal Creek unit, CPA will have a 77 MW deficit, for which it will attempt to purchase power from other suppliers.

With time this power shortage will become progressively more severe. Even with the operation of both Coal Creek units, the system will be unable to adequately serve its load after the summer of 1981.

UPA's forecast of demand for electric energy is outlined in Section IV (EA 635) of this application. This total demand is summarized in Exhibit 28, which shows UPA's reserve capacity obligation and its net generating capability of 237 megawatts. This capacity falls far short of taking care of UPA's present load demand and reserve obligation. For example, in the winter of 1975, UPA has an estimated demand of 345 megawatts plus a reserve capacity obligation of 52 megawatts, for a total capacity obligation of 397 megawatts. This leaves a generating deficiency of 160 megawatts, which deficiency UPA will seek to meet by purchases from others. By the winter of 1978, this deficiency will increase to 303 megawatts without any additional generation. Even with the addition of UPA's share of the first Coal Creek unit, UPA will still have a deficiency of 88 megawatts in the winter of 1978. It will not be until the winter of 1979 when the second Coal Creek unit becomes available that UPA will have adequate generating capability to meet its load plus reserve obligations. However, in the winter of 1980, when UPA will be receiving its full share of the Coal Creek Station capacity, it will again be deficient.

A. Power Planning Programs [EA 636(a)].

CPA and UPA are parties to the Mid-continent Area Reliability Coordination Agreement (MARCA), a regional reliability coordination council which has established criteria to be used in the planning and designing of generation and bulk power transmission facilities. These criteria have been utilized by the applicants with respect to the subject LHVTL and associated facilities. The MARCA Design Review Committee reviews all major transmission facilities to insure that the design criteria are followed.

B. Firm Purchases and Firm Sales [EA 636(b)].

Exhibit 18 shows CPA seasonal firm purchases and seasonal firm sales, Exhibit 19 shows UPA seasonal firm purchases and seasonal firm sales, and Exhibit 20 shows combined CPA-UPA seasonal firm purchases and seasonal firm sales.

C. <u>Participation Purchases and Participation Sales</u> [EA 636(c)].

Exhibit 21 shows CPA seasonal participation purchases and seasonal participation sales, Exhibit 22 shows UPA seasonal participation purchases and seasonal participation sales, and Exhibit 23 shows combined CPA-UPA seasonal participation purchases and seasonal participation sales.

D. <u>Load and Generation Capacity Data</u> [EA 636(d)].

Exhibit 24 shows CPA load and generation capacity data, Exhibit 25 shows UPA load and generation capacity data, and Exhibit 26 shows combined CPA-UPA load and generation capacity data.

E. <u>Load Capacity and Reserve as Projected with the Proposed Facility in operation</u> [EA 636(e)].

Exhibit 27 shows CPA load capacity and reserve as projected with the proposed facility in operation, Exhibit 28 shows UPA load capacity and reserve as projected with the proposed facility in operation, and Exhibit 29 shows the combined CPA-UPA load capacity and reserve as projected with the proposed facility in operation.

F. Load Capacity and Reserve as Projected [EA 636(f)].

Exhibit 30 shows CPA load capacity and reserve as projected, Exhibit 31 shows UPA load capacity and reserve as projected, and Exhibit 32 shows combined CPA-UPA load capacity and reserve as projected.

G. Proposed Capacity Additions and Proposed Capacity Retirements [EA 636(g)].

Exhibit 33 shows CPA proposed capacity addition and proposed capacity retirements; these proposals are not finalized. Both CPA and UPA are presently involved in long-range planning studies for future generation additions. Consideration is being given to both peaking and base load generation as well as to participation in base load generating units with other MAPP participants. These plans have not been finalized at the time of this application.

H. Load, Capacity Profile [EA 636(h)].

Exhibit 34 shows CPA load capacity profile, Exhibit 35 shows UPA load capacity profile, and Exhibit 36 shows combined CPA-UPA load capacity profile.

I. <u>Reserve Requirements</u> [EA 636(i)].

CPA and UPA participate in the Mid-Continent Area Power Pool (MAPP) and the Mid-Continent Area Reliability Coordination (MARCA) agreements with twenty-one other electric utilities located throughout the midwestern and northwestern United States. Participation in these agreements affords each member utility greater system reliability through the sharing of generation reserves, by provisions for emergency power during unexpected outages, and by the coordination of operating and planning activities for the entire Pool system. Members of the MAPP system also coordinate the construction of generation and transmission facilities to insure the installation of units which are efficiently sized. Each member utility has a reserve obligation equal to 15% of its annual adjusted net system demand where: Annual Adjusted Net System Demand = (Annual System Demand) - (Total Firm Purchases) + (Total Firm Sales); and where Reserve Obligation = (0.15) (Annual Adjusted Net System Demand).

XVI. <u>Consequences of Delay</u> [EA 637].

A delay of one year, or less, in the construction of the subject LHVTL to receive and transmit power generated at the Coal Creek Station by the fall of 1978 will result in severe economic consequences to the ultimate consumers of CPA and UPA. Furthermore, a one year delay will result in an unacceptable level of reliability of service, and will also result in an unacceptable reserve capacity level for CPA and UPA. These consequences would increase in magnitude for each additional year of delay.

Based upon current projections, there will be inadequate surplus capacity in the MAPP Pool to meet the deficiencies in the CPA and UPA systems. This inadequacy increases in magnitude each year as the requirements of CPA and UPA increase. The result could be that in case of emergencies CPA and UPA could suffer outages affecting large portions of their consumers.

If surplus capacity were available for purchase from others, these purchases would amount to a substantial portion of the requirements of CPA and UPA. The cost of these purchases would be an unacceptable economic burden to the ultimate consumers. For example, the additional costs of such purchases to be borne by the consumers are estimated to be $10 million in 1978, $98 million in 1979 and $112 million in 1980.

A delay in the construction will substantially increase the cost of the LHVTL because of the influence of inflation on labor and materials. Such increase in costs will increase the rates which must be borne by the ultimate consumer. To illustrate, the ±400 kV dc transmission line costs are estimated to increase by $5.0 million in the first year of delay, $10.6 million the second year and $16.7 million in the third year.

A delay will result in the untenable situation of the Coal Creek Station being commercially operable but without transmission facilities to receive the power generated. The costs associated with a completed generating plant not able to operate because of loss of transmission facilities would be enormous.

The Coal Creek generating units have been scheduled as committed units in MAPP. These units have been included in projections by MAPP to maintain acceptable minimum reserves which are necessary for reliable operation. Without these units, the MAPP reserves could fall below acceptable minimum requirements and the reliability of MAPP operation would be seriously impaired. Under certain contingency situations, the region served by MAPP (Minnesota, North Dakota, South Dakota, Iowa and western Wisconsin) could be subject to possible serious interruption of service.

A delay would require CPA and UPA and the MAPP generating network to attempt to provide the required energy with smaller, less efficient generating units. The Coal Creek Station units will use lignite, which is available in large quantities in the Underwood, North Dakota area. These units will be base loaded to the maximum extent possible thereby minimizing generation by smaller less efficient units. Many of these smaller units are peaking-type units which use petroleum products as fuel. Consequently, without the Coal Creek Station units in operation, a substantial portion of the energy to replace these units would have to be generated using oil as a fuel.

VII. Summary and Conclusion.

The applicants began serious discussion of construction of a jointly owned generating facility in 1972; authorization was given to a nationally recognized engineering consulting firm to commence a feasibility study in November of that year.

During 1973, the applicants received the aforementioned feasibility study and environmental reports on the proposed generation and transmission undertakings. A final federal environmental impact statement was issued by the U.S. Department of Agriculture Rural Electrification Administration in July of 1974.

The CU Project is the largest REA financed project in the history of the REA program, involving over $600 million in loans and loan guarantees.

Unlike many investor owned utilities whose load base is heavily urban, the applicants' loads are overwhelmingly rural. While electric consumption growth nationally has slowed and, in some instances, leveled off for temporary periods, the applicants have continued to experience load growth even in recent times of energy conservation efforts. The reason for this seems clear: farmers, heavily dependent on electricity, are not able to effect energy savings and still get their work done. Crops cannot be dried 10% less; irrigators still need to apply 8-10 inches of water per season; cows cannot be milked faster or less often or less completely.

The applicants, and in particular CPA, will be experiencing a sizeable decrease in their firm committments from the USBR. The CU Project is designed to provide the capacity needed to fill the void created by the lost Bureau power.

Considerable time and effort have been expended in connection with the CU Project. Conservative forecasts show an irrefutable need for the proposed facilities. The applicants will not be able to serve their present and future loads if this application is denied or delayed. There is no alternative way to meet the demand. The best engineering judgments conclude that the proposed facilities are of the proper size and type and are timely; they are in fact urgently needed. The applicants respectfully request that a certificate of need for the subject facilities be granted as soon as allowed by law.

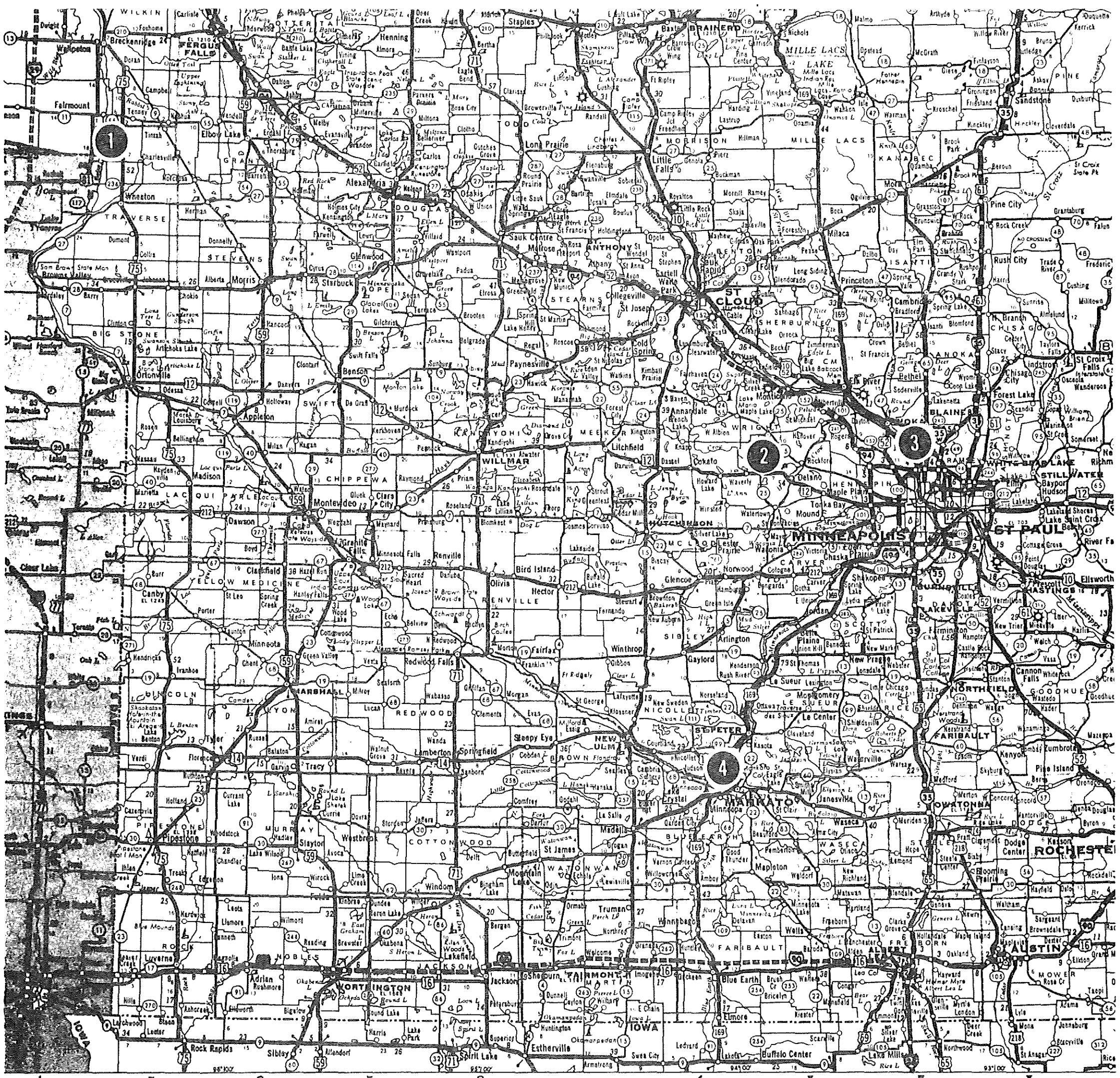
EXHIBITS

LIST OF EXHIBITS

Note: The data required by EA 635(b)(3)-(7) is supplied only for the applicants' individual systems. Due to the nature of the data, it is not supplied for the applicants' combined systems.

EXHIBIT #1

LOCATION OF TRANSMISSION LINE TERMINALS CU PROJECT



1 DC Transmission Line Entry Point.

2 Dickinson DC Terminal.

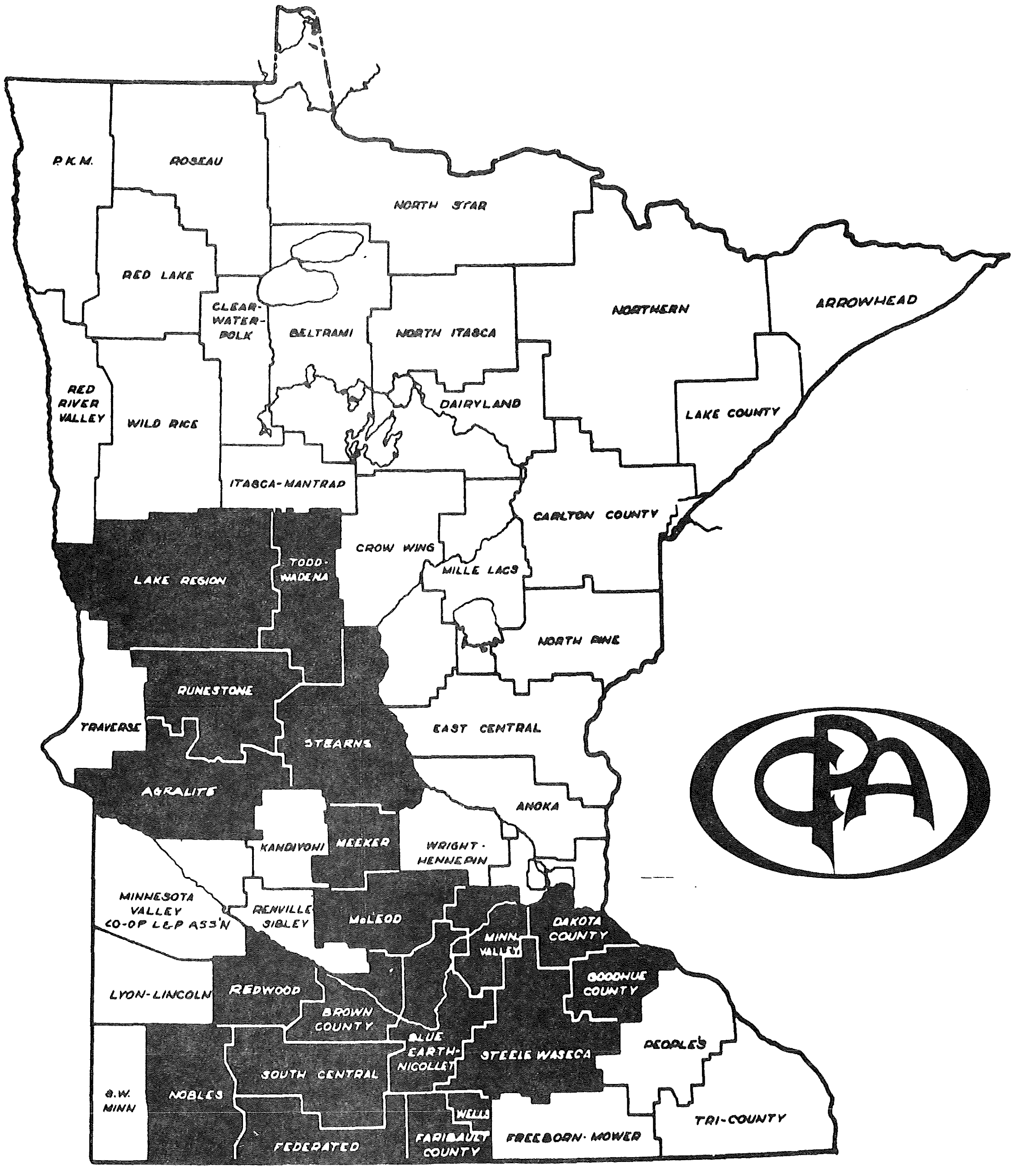
3 Coon Creek Substation.

4 Wilmarth Substation (Mankato)

EXHIBIT #2

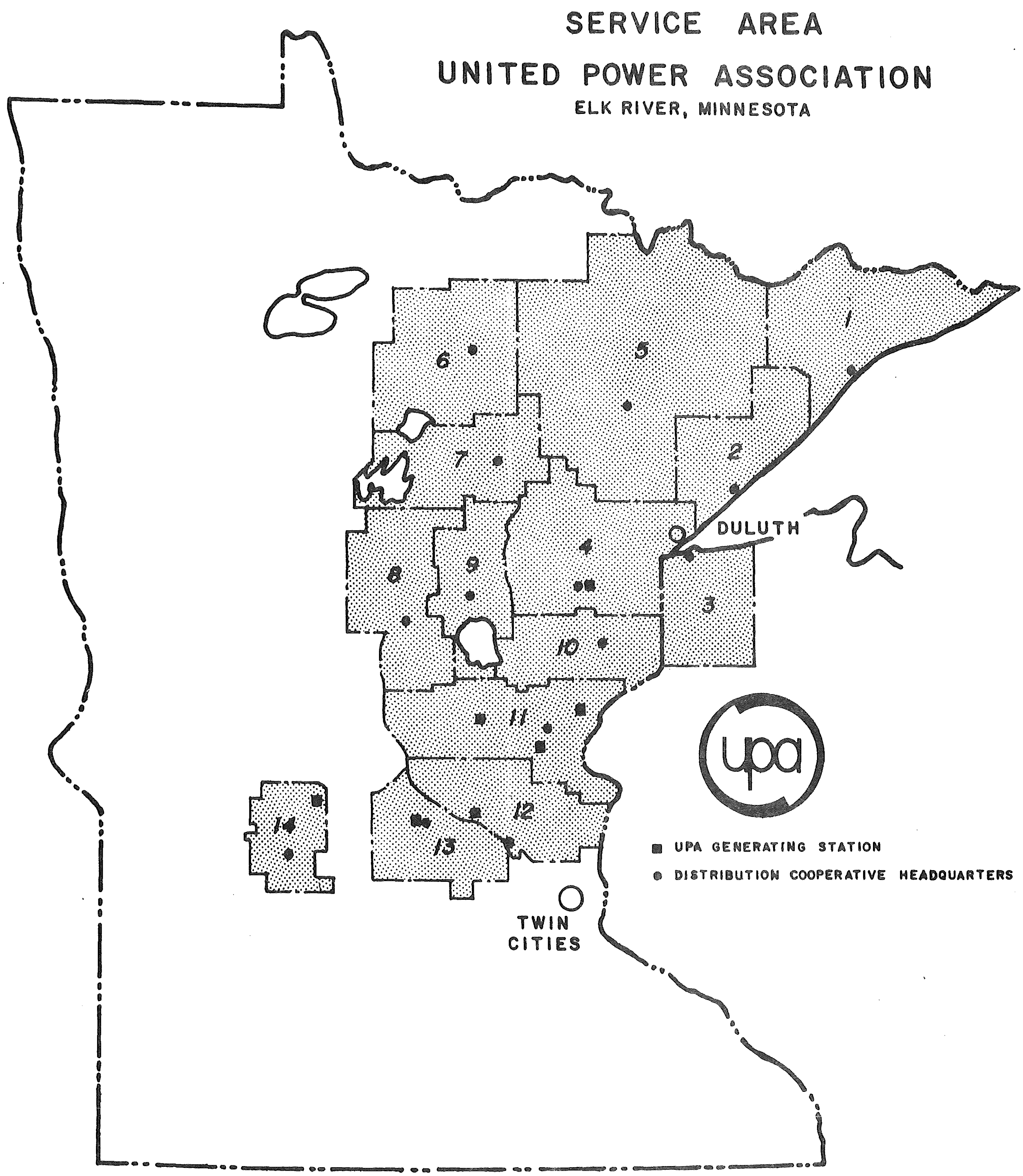
SERVICE AREA

Cooperative Power Association



■ INDICATES CO-OP POWER SYSTEMS SERVED BY CPA

EXHIBIT 3



MEMBER COOPERATIVES

1 ARROWHEAD ELECTRIC, LUTSEN
2 LAKE COUNTY, TWO HARBORS
3 HEAD OF THE LAKES, SUPERIOR
4 CARLTON COUNTY, KETTLE RIVER
5 NORTHERN ELECTRIC, VIRGINIA
6 NORTH ITASCA, BIG FORK
7 DAIRYLAND ELECTRIC, GRAND RAPIDS
8 CROW WING, BRAINERD
9 MILLE LACS ELECTRIC, AITKIN
10 NORTH PINE, FINLAYSON
11 EAST CENTRAL, BRAHAM
12 ANOKA ELECTRIC, ANOKA
13 WRIGHT-HENNEPIN, MAPLE LAKE
14 KANDIYOHI ELECTRIC, WILLMAR

EXHIBIT 4

UPA - ANNUAL ELECTRICAL CONSUMPTION
BY ULTIMATE CONSUMERS WITHIN
MINNESOTA SERVICE AREA (KWH)
EA 635 (b) (1)

YEAR**	ENERGY (KWH)*
1965	484, 955, 074
1966	530, 113, 130
1967	576, 776, 514
1968	649, 445, 011
1969	736, 835, 828
1970	824, 760, 637
1971	910, 826, 244
1972	1, 036, 785, 107
1973	1, 136, 173, 742
1974	1, 216, 882, 783
1975	1, 353, 950, 000
1976	1, 511, 000, 000
1977	1, 690, 000, 000
1978	1, 886, 300, 000
1979	2, 065, 700, 000
1980	2, 281, 300, 000
1981	2, 506, 125, 000
1982	2, 783, 400, 000
1983	3, 066, 800, 000
1984	3, 397, 700, 000
1985	3, 787, 350, 000
1986	4, 202, 500, 000
1987	4, 690, 000, 000
1988	5, 252, 700, 000
1989	5, 898, 520, 000
1990	6, 555, 500, 000

*kwh - kilowatt hours
** 1965-1974 are history
1975-1990 are forecast

EXHIBIT 5

CPA ANNUAL ELECTRICAL CONSUMPTION BY ULTIMATE CONSUMER (MWH)

EA635 (b) (2)

	(i) farm	(ii) irrigation	(iii) non-farm residential	(iv) commercial	(v) mining	(vi) industrial
1964	600,884	57	24,490	30,712	0	21,620
1965	625,638	108	51,708	33,301	0	23,447
1966	657,733	67	58,965	36,729	0	25,478
1967	694,483	256	67,753	41,323	0	27,796
1968	737,633	307	81,011	48,569	0	30,720
1969	793,960	897	100,175	55,734	0	32,073
1970	863,056	1,597	124,047	61,678	0	47,871
1971	915,374	2,265	150,901	67,329	0	63,198
1972	986,849	1,359	171,222	77,531	0	73,370
1973	1,001,357	2,591	192,691	85,501	0	84,473
1974	1,071,378	5,121	217,618	85,144	0	97,036
1975	1,194,000	6,000	243,000	95,000	0	108,000
1976	1,308,000	6,000	266,000	104,000	0	119,000
1977	1,437,000	7,000	292,000	115,000	0	130,000
1978	1,582,000	8,000	322,000	127,000	0	144,000
1979	1,720,000	8,000	351,000	136,000	0	156,000
1980	1,870,000	9,000	380,000	148,000	0	170,000
1981	2,034,000	10,000	414,000	162,000	0	184,000
1982	2,213,000	11,000	451,000	176,000	0	201,000
1983	2,413,000	11,000	491,000	192,000	0	219,000
1984	2,631,000	12,000	535,000	210,000	0	239,000
1985	2,872,000	14,000	584,000	228,000	0	260,000
1986	3,139,000	15,000	637,000	250,000	0	285,000
1987	3,432,000	16,000	697,000	273,000	0	311,000
1988	3,755,000	18,000	763,000	299,000	0	340,000
1989	4,113,000	19,000	836,000	327,000	0	373,000
1990	4,509,000	21,000	916,000	358,000	0	409,000

EXHIBIT 5
CPA ANNUAL ELECTRICAL CONSUMPTION BY ULTIMATE CONSUMER (MWH)
EA635 (b) (2)

	(vii) street & highway lighting	(viii) electrical transportation	(ix) other	(x) total
1964	376	0	3,084	681,223
1965	531	0	3,342	738,075
1966	734	0	3,355	783,061
1967	1,193	0	3,516	836,320
1968	1,335	0	3,980	903,555
1969	2,049	0	5,290	990,178
1970	2,736	0	5,886	1,106,871
1971	3,341	0	5,832	1,208,240
1972	3,649	0	5,040	1,319,020
1973	4,030	0	5,900	1,376,543
1974	3,984	0	6,564	1,486,845
1975	5,000	0	7,000	1,658,000
1976	5,000	0	8,000	1,816,000
1977	5,000	0	9,000	1,995,000
1978	6,000	0	10,000	2,199,000
1979	6,000	0	11,000	2,388,000
1980	8,000	0	11,000	2,596,000
1981	8,000	0	12,000	2,824,000
1982	8,000	0	14,000	3,074,000
1983	9,000	0	15,000	3,350,000
1984	10,000	0	16,000	3,653,000
1985	11,000	0	18,000	3,987,000
1986	11,000	0	19,00	4,356,000
1987	13,000	0	21,000	4,763,000
1988	14,000	0	23,000	5,212,000
1989	16,000	0	25,000	5,709,000
1990	17,000	0	28,000	6,258,000

EXHIBIT 6

UPA - ANNUAL ELECTRICAL CONSUMPTION
BY ULTIMATE CONSUMER (KWH)
EA 635 (b) (2)

		1965	1966	1967
(i)	Farm	278,074,224	299,424,672	326,202,336
(ii)	Irrigation	197,140	423,810	479,136
(iii)	Non-farm	103,171,194	113,716,454	127,333,447
(iv)	Commercial	71,513,052	75,842,724	80,678,628
(v)	Mining	0	0	0
(vi)	Industrial	41,890,296	51,197,880	53,029,759
(vii)	Street and Highway Lighting	2,640,528	2,835,750	2,872,968
(viii)	Electrified Transportation	0	0	0
(ix)	Other	0	0	0
(x)	Sum of all Categories	497,486,434	543,441,290	590,596,274

All Numbers Are in Kilowatt Hours

EXHIBIT 6

		1968	1969	1970
(i)	Farm	357,557,760	399,063,240	438,796,128
(ii)	Irrigation	692,040	1,234,392	1,399,797
(iii)	Non-farm	144,609,719	162,435,484	189,192,095
(iv)	Commercial	87,729,780	98,302,152	113,025,096
(v)	Mining	0	0	0
(vi)	Industrial	70,868,720	88,645,572	96,238,800
(vii)	Street and Highway Lighting	3,091,392	3,465,188	3,808,721
(viii)	Electrified Transportation	0	0	0
(ix)	Other	0	0	0
(x)	Sum of all Categories	664,549,411	753,146,028	842,460,637

All Numbers Are in Kilowatt Hours

EXHIBIT 6

		1971	1972	1973
(i)	Farm	483,660,000	549,069,768	580,673,664
(ii)	Irrigation	1,495,819	959,105	1,271,727
(iii)	Non-farm	206,013,925	229,018,998	245,291,340
(iv)	Commercial	123,958,340	141,090,984	149,717,340
(v)	Mining	0	0	0
(vi)	Industrial	110,293,040	133,573,857	176,821,479
(vii)	Street and Highway Lighting	4,236,120	4,527,395	4,672,692
(viii)	Electrified Transportation	0	0	0
(ix)	Other	0	0	0
(x)	Sum of all Categories	929,657,244	1,058,240,107	1,158,448,242

All Numbers Are in Kilowatt Hours

EXHIBIT 6

		1974	1975	1976
(i)	Farm	654,301,580	730,000,000	810,000,000
(ii)	Irrigation	1,836,802	2,100,000	2,350,000
(iii)	Non-farm	265,369,831	285,000,000	305,000,000
(iv)	Commercial	155,567,027	172,000,000	193,000,000
(v)	Mining	0	0	0
(vi)	Industrial	155,157,946	185,000,000	222,000,000
(vii)	Street and Highway Lighting	4,880,457	5,150,000	5,600,000
(viii)	Electrified Transportation	0	0	0
(ix)	Other	0	0	0
(x)	Sum of all Categories	1,237,113,643	1,379,250,000	1,537,950,000

All Numbers Are in Kilowatt Hours

EXHIBIT 6

		1977	1978	1979
(i)	Farm	900,000,000	995,000,000	1,080,000,000
(ii)	Irrigation	2,650,000	3,000,000	3,300,000
(iii)	Non-farm	326,000,000	351,000,000	383,000,000
(iv)	Commercial	216,500,000	243,000,000	266,500,000
(v)	Mining	0	0	0
(vi)	Industrial	268,000,000	320,000,000	360,000,000
(vii)	Street and Highway Lighting	5,900,000	6,300,000	6,900,000
(viii)	Electrified Transportation	0	0	0
(ix)	Other	0	0	0
(x)	Sum of all Categories	1,719,050,000	1,918,300,000	2,099,700,000

All Numbers Are in Kilowatt Hours

EXHIBIT 6

		1980	1981	1982
(i)	Farm	1,180,000,000	1,280,000,000	1,400,000,000
(ii)	Irrigation	3,600,000	4,000,000	4,400,000
(iii)	Non-farm	423,000,000	458,500,000	502,000,000
(iv)	Commercial	293,000,000	323,500,000	370,000,000
(v)	Mining	0	0	0
(vi)	Industrial	410,000,000	470,000,000	540,000,000
(vii)	Street and Highway Lighting	7,500,000	8,125,000	9,000,000
(viii)	Electrified Transportation	0	0	0
(ix)	Other	0	0	0
(x)	Sum of all Categories	2,317,100,000	2,544,125,000	2,825,400,000

All Numbers Are in Kilowatt Hours

EXHIBIT 6

		1983	1984	1985
(i)	Farm	1,525,000,000	1,680,000,000	1,850,000,000
(ii)	Irrigation	4,900,000	5,500,000	6,200,000
(iii)	Non-farm	555,000,000	603,000,000	653,000,000
(iv)	Commercial	397,000,000	431,000,000	483,000,000
(v)	Mining	0	0	0
(vi)	Industrial	620,000,000	715,000,000	835,000,000
(vii)	Street and Highway Lighting	9,900,000	10,700,000	11,150,000
(viii)	Electrified Transportation	0	0	0
(ix)	Other	0	0	0
(x)	Sum of all Categories	3,111,800,000	3,445,200,000	3,838,350,000

All Numbers Are in Kilowatt Hours

EXHIBIT 6

		1986	1987	1988
(i)	Farm	2,030,000,000	2,250,000,000	2,450,000,000
(ii)	Irrigation	7,000,000	7,900,000	9,000,000
(iii)	Non-farm	707,000,000	770,000,000	838,000,000
(iv)	Commercial	531,000,000	586,500,000	654,000,000
(v)	Mining	0	0	0
(vi)	Industrial	970,000,000	1,120,000,000	1,350,000,000
(vii)	Street and Highway Lighting	12,500,000	13,500,000	14,700,000
(viii)	Electrified Transportation	0	0	0
(ix)	Other	0	0	0
(x)	Sum of all Categories	4,257,500,000	4,747,900,000	5,315,700,000

All Numbers Are in Kilowatt Hours

EXHIBIT 6

		1989	1990
(i)	Farm	2,700,000,000	2,950,000,000
(ii)	Irrigation	10,020,000	11,500,000
(iii)	Non-farm	910,000,000	990,000,000
(iv)	Commercial	730,000,000	810,000,000
(v)	Mining	0	0
(vi)	Industrial	1,600,000,000	1,850,000,000
(vii)	Street and Highway Lighting	16,500,000	17,000,000
(viii)	Electrified Transportation	0	0
(ix)	Other	0	0
(x)	Sum of all Categories	5,966,520,000	6,628,500,000

All Numbers Are in Kilowatt Hours

EXHIBIT 7

COMBINED ANNUAL ELECTRICAL CONSUMPTION BY ULTIMATE CONSUMER (KWH) EA 635 (b) (2)

	Farm	Irrigation	Non-farm
1965	903,712	305	154,879
1966	957,158	491	172,681
1967	1,020,685	735	195,085
1968	1,095,191	999	225,621
1969	1,193,023	2,131	262,611
1970	1,301,852	2,997	313,239
1971	1,399,034	3,761	356,915
1972	1,535,919	2,318	400,241
1973	1,582,031	3,863	437,982
1974	1,725,680	6,958	482,988
1975	1,924,000	8,100	528,000
1976	2,118,000	8,350	571,000
1977	2,337,000	9,650	618,000
1978	2,577,000	11,000	673,000
1979	2,800,000	11,300	734,000
1980	3,050,000	12,600	803,000
1981	3,314,000	14,000	872,500
1982	3,613,000	15,400	953,000
1983	3,938,000	15,900	1,046,000
1984	4,311,000	17,500	1,138,000
1985	4,722,000	20,200	1,237,000
1986	5,169,000	22,000	1,344,000
1987	5,682,000	23,900	1,467,000
1988	6,205,000	27,000	1,601,000
1989	6,813,000	29,020	1,746,000
1990	7,459,000	32,500	1,906,000

All figures are in Kilowatt Hours (KWH)

EXHIBIT 7

	Commercial	Mining	Industrial
1965	104,814	0	65,337
1966	112,572	0	76,676
1967	122,002	0	80,826
1968	136,329	0	101,589
1969	154,036	0	120,719
1970	174,703	0	144,110
1971	191,287	0	173,491
1972	218,622	0	206,944
1973	235,218	0	261,294
1974	240,711	0	252,194
1975	267,000	0	293,000
1976	297,000	0	341,000
1977	331,500	0	398,000
1978	370,000	0	464,000
1979	402,500	0	516,000
1980	441,000	0	580,000
1981	485,500	0	654,000
1982	546,000	0	741,000
1983	589,000	0	839,000
1984	641,000	0	954,000
1985	711,000	0	1,095,000
1986	781,000	0	1,255,000
1987	859,500	0	1,431,000
1988	953,000	0	1,690,000
1989	1,057,000	0	1,973,000
1990	1,168,000	0	2,259,000

All figures are in Kilowatt Hours (KWH)

EXHIBIT 7

	Street & Highway Lighting	Electrical Transportation	Other	Total
1965	3,172	0	3,342	1,235,561
1966	3,570	0	3,355	1,326,503
1967	4,066	0	3,516	1,426,915
1968	4,426	0	3,980	1,568,105
1969	5,514	0	5,290	1,743,324
1970	6,545	0	5,886	1,949,332
1971	7,577	0	5,832	2,137,897
1972	8,176	0	5,040	2,377,260
1973	8,703	0	5,900	2,534,991
1974	8,864	0	6,564	2,723,959
1975	10,150	0	7,000	3,037,250
1976	10,600	0	8,000	3,353,950
1977	10,900	0	9,000	3,714,050
1978	12,300	0	10,000	4,117,300
1979	12,900	0	11,000	4,487,700
1980	15,500	0	11,000	4,913,100
1981	16,125	0	12,000	5,368,125
1982	17,000	0	14,000	5,899,400
1983	18,900	0	15,000	6,461,800
1984	20,700	0	16,000	7,098,200
1985	22,150	0	18,000	7,825,350
1986	23,500	0	19,000	8,613,500
1987	26,500	0	21,000	9,510,900
1988	28,700	0	23,000	10,527,700
1989	32,500	0	25,000	11,675,520
1990	34,000	0	28,000	12,886,500

All figures are in Kilowatt Hours (KWH)

EXHIBIT 8

CPA ESTIMATE OF DEMAND FOR POWER BY ULTIMATE CONSUMERS AT TIME OF SYSTEM PEAK DEMAND

EA635 (b) (3)

	(i) farm	(ii) irri-gation	(iii) non-farm resi-dential	(iv) com-mercial	(v) mining	(vi) indus-trial	(vii) street and high-way lighting	(viii) elec-trical transpor-tation	(ix) other	(x) total
1964	130	0	27	10	0	12	1	0	1	181
1965	134	0	27	11	0	12	1	0	1	186
1966	149	0	30	12	0	13	1	0	1	206
1967	150	0	30	12	0	14	1	0	1	208
1968	170	0	34	14	0	15	1	0	1	235
1969	182	0	37	14	0	17	1	0	1	252
1970	198	0	40	16	0	18	1	0	1	274
1971	210	0	43	17	0	19	1	0	1	291
1972	235	0	48	19	0	21	1	0	1	325
1973	235	0	48	19	0	21	1	0	1	325
1974	254	0	52	20	0	23	1	0	2	352
1975	283	0	57	22	0	26	1	0	2	391
1976	309	0	63	25	0	28	1	0	2	428
1977	340	0	69	27	0	31	1	0	2	470
1978	374	0	76	30	0	34	1	0	2	517
1979	405	0	82	32	0	37	2	0	3	561
1980	440	0	89	35	0	40	2	0	3	609
1981	479	0	97	38	0	43	2	0	3	662
1982	522	0	105	41	0	47	2	0	3	720
1983	567	0	115	45	0	51	2	0	4	784
1984	619	0	125	49	0	56	2	0	4	855
1985	675	0	137	53	0	61	3	0	4	933
1986	737	0	149	58	0	66	3	0	5	1018
1987	806	0	163	64	0	73	3	0	5	1114
1988	881	0	179	70	0	79	3	0	5	1217
1989	965	0	195	76	0	87	4	0	6	1333
1990	1058	0	214	84	0	95	4	0	6	1461

EXHIBIT 9

UPA - ESTIMATE OF DEMAND FOR POWER
BY ULTIMATE CONSUMERS AT TIME OF
SYSTEM PEAK DEMAND (MW)
EA 635 (b) (3)

Class* -	(i)	(ii)	(iii)	(iv)	(v)	(vi)	(vii)	(viii)	(ix)	(x)
1965	67	0	38	15	0	8	1	0	0	129
1966	74	0	41	17	0	8	1	0	0	141
1967	88	0	49	20	0	10	1	0	0	168
1968	95	0	53	22	0	11	1	0	0	182
1969	106	0	58	24	0	12	1	0	0	201
1970	117	0	65	26	0	13	1	0	0	222
1971	135	0	75	31	0	15	1	0	0	257
1972	146	0	80	34	0	17	1	0	0	278
1973	152	0	84	35	0	17	1	0	0	289
1974	160	0	89	36	0	18	1	0	0	304
1975	182	0	100	41	0	21	1	0	0	345
1976	199	0	109	45	0	23	2	0	0	378
1977	217	0	120	50	0	25	2	0	0	414

* (i) = Farm
(ii) = Irrigation
(iii) = Non-farm
(iv) = Commercial
(v) = Mining
(vi) = Industrial
(vii) = Street and Highway Lighting
(viii) = Electrified Transportation
(ix) = Other
(x) = Sum of All Categories

All Numbers Are in Megawatts

EXHIBIT 9

Class* -	(i)	(ii)	(iii)	(iv)	(v)	(vi)	(vii)	(viii)	(ix)	(x)
1978	247	0	136	57	0	28	2	0	0	470
1979	281	0	156	64	0	32	2	0	0	535
1980	310	0	170	71	0	35	2	0	0	588
1981	339	0	187	78	0	39	3	0	0	646
1982	373	0	206	85	0	43	3	0	0	710
1983	410	0	226	94	0	47	3	0	0	780
1984	451	0	248	104	0	51	3	0	0	857
1985	496	0	274	113	0	57	4	0	0	944
1986	546	0	301	125	0	62	4	0	0	1038
1987	602	0	332	137	0	69	4	0	0	1144
1988	663	0	366	150	0	76	5	0	0	1260
1989	729	0	402	166	0	83	6	0	0	1386
1990	802	0	444	183	0	92	8	0	0	1529

* (i) = Farm — (vi) = Industrial

(ii) = Irrigation — (vii) = Street and Highway Lighting

(iii) = Non-farm — (viii) = Electrified Transportation

(iv) = Commercial — (ix) = Other

(v) = Mining — (x) = Sum of All Categories

All Numbers Are in Megawatts

EXHIBIT 10
CPA SYSTEM PEAK DEMAND BY MONTH (MW)
EA635 (b) (4)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
1964	174	162	156	155	138	132	132	132	136	148	154	181
1965	183	186	175	165	149	141	135	137	144	150	170	177
1966	188	206	183	166	154	139	150	147	148	161	189	192
1967	208	203	201	177	166	154	154	154	151	173	202	202
1968	235	215	208	188	173	165	169	169	169	181	218	236
1969	252	236	211	210	179	175	184	180	179	202	243	242
1970	253	271	234	224	204	196	206	205	202	236	246	274
1971	284	291	254	238	208	219	216	222	223	252	289	284
1972	322	310	288	250	236	233	232	254	240	274	302	325
1973	325	305	284	265	249	256	270	268	279	278	322	314
1974	352	329	293	297	262	259	309	305	286	314	317	338
1975*	391	368	340	321	297	301	332	328	325	332	368	379
1976	428	402	372	351	325	330	364	360	355	364	402	415
1977	470	442	409	385	357	362	400	395	390	400	442	456
1978	517	486	450	424	393	398	439	434	429	439	486	501
1979	561	527	488	460	426	432	477	471	466	477	527	544
1980	609	572	530	499	463	469	518	512	505	518	572	591
1981	662	622	576	543	503	510	563	556	549	563	622	642
1982	720	677	626	590	547	554	612	605	598	612	677	698
1983	784	737	682	643	596	604	666	659	651	666	737	760
1984	855	804	744	701	650	658	727	718	710	727	804	829
1985	933	877	812	765	709	718	793	784	774	793	877	905
1986	1018	957	886	835	774	784	865	855	845	865	957	987
1987	1114	1047	969	913	847	858	947	936	925	947	1047	1081
1988	1217	1143	1059	998	925	937	1034	1022	1010	1034	1143	1180
1989	1333	1253	1160	1093	1013	1026	1133	1120	1106	1133	1253	1293
1990	1461	1373	1271	1198	1110	1125	1242	1227	1213	1242	1373	1417

*The monthly projection percentages for 1975 thru 1990 are as follows:

Jan	100	May	76	Sept	83
Feb	94	Jun	77	Oct	85
Mar	87	Jul	85	Nov	94
Apr	82	Aug	84	Dec	97

EXHIBIT 11

UPA - SYSTEM PEAK DEMAND BY MONTH (MW)
EA 635 (b) (4)

Year*	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
1965	120	116	108	101	99	93	100	105	111	108	122	129
1966	129	124	117	106	105	105	111	112	113	107	118	141
1967	141	137	129	116	107	106	114	116	116	130	139	168
1968	168	150	145	136	120	123	127	138	129	143	152	182
1969	182	164	155	142	136	135	145	157	153	158	172	201
1970	201	189	176	162	138	162	167	160	158	176	199	222
1971	222	219	184	174	159	172	172	177	183	187	210	257
1972	257	238	217	189	173	179	202	212	196	212	235	278
1973	277	259	227	228	198	221	231	254	228	226	260	289
1974	283	270	243	227	214	224	267	245	230	234	271	304
1975	328	311	277	258	241	259	286	300	262	272	309	345
1976	358	338	302	280	262	281	311	326	284	296	335	378
1977	393	373	332	328	289	310	343	360	313	326	370	414

The Monthly Projection Percentages Are as Follows:

Jan. = 95.4%	Jul. = 83.0%
Feb. = 90.2	Aug. = 87.0 up to 1982, then 89.0%
Mar. = 80.5	Sep. = 75.9
Apr. = 74.8	Oct. = 79.1
May = 69.9	Nov. = 89.5
Jun. = 75.0	Dec. = 100.0

* 1965-1974 is History
1975-1990 is Forecast

All Numbers Are in Megawatts

EXHIBIT 11

Year*	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
1978	448	423	378	351	328	352	390	408	356	371	420	470
1979	510	482	430	400	373	401	444	465	406	423	478	535
1980	560	530	473	439	411	441	488	511	446	465	526	588
1981	616	582	520	483	451	484	536	562	490	510	578	646
1982	677	640	571	531	496	532	589	617	538	561	635	710
1983	744	703	627	583	545	585	647	694	592	616	698	780
1984	817	773	689	641	599	642	711	762	650	677	767	857
1985	900	851	759	706	659	708	783	840	716	746	844	944
1986	990	936	835	776	725	778	861	923	787	821	929	1038
1987	1091	1031	920	855	799	858	949	1018	868	904	1023	1144
1988	1202	1136	1014	942	880	945	1045	1121	956	996	1127	1260
1989	1322	1250	1115	1036	968	1039	1150	1233	1051	1096	1240	1386
1990	1458	1379	1230	1143	1068	1146	1269	1360	1160	1209	1368	1529

The Monthly Projection Percentages Are as Follows:

Jan.	= 95.4%	Jul.	= 83.0%
Feb.	= 90.2	Aug.	= 87.0 up to 1982, then 89.0%
Mar.	= 80.5	Sep.	= 75.9
Apr.	= 74.8	Oct.	= 79.1
May	= 69.9	Nov.	= 89.5
Jun.	= 75.0	Dec.	= 100.0

* 1965-1974 is History
1975-1990 is Forecast

All Numbers are in Megawatts

EXHIBIT 12
CPA MONTHLY AVERAGE SYSTEM DAILY LOAD FACTOR
EA635 (b) (5)

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
1964	.60	.59	.63	.59	.58	.57	.62	.60	.57	.52	.55	.60
1965	.62	.62	.63	.57	.57	.57	.58	.60	.56	.55	.56	.58
1966	.60	.59	.58	.59	.60	.61	.60	.60	.57	.55	.57	.59
1967	.61	.62	.61	.58	.59	.60	.60	.60	.60	.55	.58	.59
1968	.60	.62	.62	.56	.62	.61	.58	.62	.59	.58	.56	.59
1969	.63	.63	.62	.58	.60	.60	.60	.62	.60	.55	.58	.60
1970	.63	.61	.63	.61	.59	.61	.61	.62	.60	.56	.59	.61
1971	.65	.64	.62	.60	.61	.60	.62	.60	.59	.56	.57	.60
1972	.60	.66	.62	.62	.60	.61	.61	.60	.59	.55	.60	.63
1973	.63	.64	.61	.60	.61	.59	.60	.60	.57	.58	.58	.62
1974	.64	.64	.65	.62	.62	.62	.59	.58	.56	.56	.58	.62
1975*	.62	.62	.62	.59	.60	.60	.60	.60	.58	.56	.57	.60

*The monthly load factor shown for 1975 applies to all years, 1975 thru 1990.

EXHIBIT 13

UPA - MONTHLY AVERAGE SYSTEM
DAILY LOAD FACTOR
EA 635 (b) (5)

Year*	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
1965 to 1972	.658	.677	.696	.666	.697	.670	.652	.668	.618	.655	.646	.637
1973	.578	.618	.632	.567	.669	.633	.605	.643	.545	.618	.631	.579
1974	.701	.721	.712	.687	.723	.698	.666	.672	.691	.692	.660	.695
1975	.696	.692	.745	.743	.700	.680	.684	.689	.618	.655	.646	.637
1976 to 1990	.658	.677	.696	.666	.697	.670	.652	.668	.618	.655	.646	.637

* January 1965 to December 1972 is estimated as average for month in actual data.

January 1973 to August 1975 is actual.

September 1975 to December 1990 is estimated as average for month in actual data.

EXHIBIT 14
CPA MONTHLY AVERAGE SYSTEM WEEKDAY LOAD FACTOR
EA635 (b) (6)

	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sept	Oct	Nov	Dec
1964 to 1990	.71	.76	.73	.75	.76	.77	.75	.75	.73	.67	.64	.68

The weekday load factor is only an estimate based upon an analysis of hourly data for 1971-72. Therefore, the monthly load factors shown apply to all years 1964 thru 1990.

EXHIBIT 15

UPA - MONTHLY AVERAGE SYSTEM
WEEKDAY LOAD FACTOR
EA 635 (b) (6)

Year*	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
1965 to 1972	.660	.678	.688	.645	.690	.657	.619	.679	.624	.654	.647	.649
1973	.579	.595	.610	.528	.644	.615	.592	.628	.563	.614	.630	.600
1974	.703	.730	.700	.691	.727	.685	.674	.679	.685	.694	.663	.698
1975	.699	.709	.755	.717	.698	.670	.691	.730	.624	.654	.647	.649
1976 to 1990	.660	.678	.688	.645	.690	.657	.619	.679	.624	.654	.647	.649

* January 1965 to December 1972 is estimated as the average of actual data.

January 1973 to August 1975 is actual.

September 1975 to December 1990 is estimated as the average of actual data.

EXHIBIT 16

CPA MONTHLY AVERAGE SYSTEM WEEKEND LOAD

EA635 (b) (7)

	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sept	Oct	Nov	Dec
1964 to 1990	.71	.71	.72	.74	.67	.74	.79	.79	.76	.70	.70	.70

The weekday load factor is only an estimate based upon an analysis of hourly data for 1971-72. Therefore, the monthly load factors shown apply to all years 1964 thru 1990.

EXHIBIT 17

UPA - MONTHLY AVERAGE SYSTEM
WEEKEND LOAD FACTOR
EA 635 (b) (7)

Year*	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
1965 to 1972	.700	.730	.734	.751	.762	.743	.695	.729	.662	.688	.685	.694
1973	.694	.710	.739	.733	.762	.758	.649	.683	.593	.652	.679	.697
1974	.704	.759	.703	.750	.770	.730	.695	.743	.732	.723	.690	.690
1975	.701	.722	.761	.769	.755	.740	.740	.762	.662	.688	.685	.694
1976 to 1990	.700	.730	.734	.751	.762	.743	.695	.729	.662	.688	.685	.694

* January 1965 to December 1972 is estimated as the average of actual data.

January 1973 to August 1975 is actual.

September 1975 to December 1990 is estimated as the average of actual data.

EXHIBIT 18
CPA SEASONAL FIRM PURCHASES AND SEASONAL FIRM SALES
EA636 (b)

Year		PURCHASES (MW) USBR	DPC	ISP	NSP	MPC	IPL	LSDP	OTP	UPA	SALES(MW)
1964	S	75		20	37						
	W	91		26	46						
1965	S	79	36	21	4						
	W	112	20	28	30						
1966	S	86	20	22	23						None for 1964 through 1990
	W	121	17	30	36						
1967	S	102	28	23	18						
	W	139	5	32	52						
1968	S	104	23	15	1				15	11	
	W	112									
1969	S	88									
	W	114									
1970	S	104									
	W	136									
1971	S	132									
	W	150									
1972	S	145									
	W	143									
1973	S	135				2					
	W	160									
1974	S	175				4					
	W	138									
1975	S	127					13	17			
	W	291									
1976	S	164									
	W	325									
1977	S	106									
	W	111									

EXHIBIT 18

CPA SEASONAL FIRM PURCHASES AND SEASONAL FIRM SALES

EA636 (b)

Year		USBR
1978	S	86
	W	111
1979	S	86
	W	111
1980	S	86
	W	111
1981	S	86
	W	111
1982	S	86
	W	111
1983	S	86
	W	111
1984	S	86
	W	111
1985	S	86
	W	111
1986	S	86
	W	111
1988	S	86
	W	111
1989	S	86
	W	111
1990	S	86
	W	111

EXHIBIT 19

UPA- SEASONAL FIRM PURCHASES AND
SEASONAL FIRM SALES (MW)
EA 636 (b)

	YEAR	1965		1966		1967		1968	
	SEASON*	S	W	S	W	S	W	S	W
PURCHASES	SYSTEM								
	MP&L	36	45	40	61	47	-	-	-
	USBR	5	6	5	6	5	6	5	6
	OTPC	2	2	3	19	-	-	-	-
	NSP	-	10	-	-	-	-	-	-
TOTAL FIRM PURCHASES		43	63	48	86	52	6	5	6
SALES	SYSTEM								
	NSP	-	-	-	-	7	-	-	4
TOTAL FIRM SALES		-	-	-	-	7	-	-	4

All numbers are in megawatts

* Summer: May 1 - October 31; Winter: Nov. 1 - Apr. 30

EXHIBIT 19

PURCHASES	YEAR	1969		1970		1971	
	SEASON*	S	W	S	W	S	W
	SYSTEM						
	DPC	1	6	1	2	-	2
	IPS	-	-	-	-	-	-
	MPC	-	-	-	1	-	4
	LSDP	-	2	-	2	-	1
	NWPS	-	2	-	-	-	1
	ISP	-	6	1	-	-	-
	NSP	-	-	-	-	-	-
	USBR	5	6	5	6	11	6
	OTPC	-	-	-	-	-	-
	IIGE	-	-	-	-	-	-
TOTAL FIRM PURCHASES		6	22	7	11	11	14

SALES	YEAR	1969		1970		1971	
	SEASON*	S	W	S	W	S	W
	SYSTEM						
	NSP	1	1	-	-	2	-
	Hutchinson	-	-	-	6	6	-
	Elk River	-	1	1	1	1	1
	ISP	-	-	-	-	2	-
TOTAL FIRM SALES		1	2	1	7	11	1

* Summer: May 1 - October 31; Winter: Nov. 1 - Apr. 30
All numbers are in megawatts

EXHIBIT 19

PURCHASES	YEAR	1972		1973		1974	
	SEASON*	S	W	S	W	S	W
	SYSTEM						
	DPC	-	-	-	-	2	-
	IPS	-	-	-	-	-	-
	MPC	3	2	6	-	3	10
	LSDP	1	-	-	-	-	4
	NWPS	-	-	-	-	1	-
	ISP	-	7	-	-	-	-
	NSP	-	1	-	9	-	24
	USBR	5	36	5	25	5	6
	OTPC	-	-	-	-	-	7
	IIGE	-	-	-	-	-	16
TOTAL FIRM PURCHASES		9	46	11	34	11	67

SALES	YEAR	1972		1973		1974	
	SEASON*	S	W	S	W	S	W
	SYSTEM						
	NSP	-	-	-	-	-	-
	Hutchinson	-	-	-	-	-	-
	Elk River	1	2	-	-	-	-
	ISP	-	-	-	-	-	-
TOTAL FIRM SALES		1	2	-	-	-	-

* Summer: May 1 - Oct. 31; Winter: Nov. 1 - Apr. 30
All numbers are in megawatts

EXHIBIT 19

	YEAR	1975		1976		1977	
	SEASON*	S	W	S	W	S	W
PURCHASES	SYSTEM						
	IPL	8	-	-	-	-	-
	Willmar	-	-	-	-	-	-
	USBR	5	6	5	6	5	6
	NSP	-	20	-	-	-	-
TOTAL FIRM PURCHASES		13	26	5	6	5	6

* Summer: May 1 - Oct. 31; Winter: Nov. 1 - Apr. 30
All numbers are in megawatts

TOTAL FIRM SALES

None for the years 1975 to 1990.

EXHIBIT 19

PURCHASES	YEAR	1978		1979		1980	
	SEASON*	S	W	S	W	S	W
	SYSTEM						
	IPL	-	-	-	-	-	-
	Willmar	-	-	-	-	-	-
	USBR	5	6	5	6	5	6
	NSP	-	-	-	-	-	-
TOTAL FIRM PURCHASES		5	6	5	6	5	6

* Summer: May 1 - Oct. 31; Winter: Nov. 1 - Apr. 30
All numbers are in megawatts

EXHIBT 19

	YEAR	1981		1982		1983	
	SEASON*	S	W	S	W	S	W
PURCHASES	SYSTEM						
	USBR	5	6	5	6	5	6
TOTAL FIRM PURCHASES		5	6	5	6	5	6

* Summer: May 1 - Oct. 31; Winter: Nov. 1 - Apr. 30
All numbers are in megawatts

EXHIBIT 19

	YEAR	1984		1985		1986	
	SEASON*	S	W	S	W	S	W
PURCHASES	SYSTEM						
	USBR	5	6	5	6	5	6
TOTAL FIRM PURCHASES		5	6	5	6	5	6

* Summer: May 1 - Oct. 31; Winter: Nov. 1 - Apr. 30
All numbers are in megawatts

EXHIBIT 19

PURCHASES	SYSTEM	1987 S	1987 W	1988 S	1988 W	1989 S	1989 W	1990 S	1990 W
	USBR	5	6	5	6	5	6	5	6
TOTAL FIRM PURCHASES		5	6	5	6	5	6	5	6

* Summer: May 1 - Oct. 31; Winter: Nov. 1 - Apr. 30
All numbers are in megawatts

EXHIBIT 20

COMBINED SEASONAL FIRM PURCHASES AND
SEASONAL FIRM SALES (MW)
EA 636 (b)

	YEAR	1965		1966		1967		1968	
	SEASON*	S	W	S	W	S	W	S	W
PURCHASES	SYSTEM								
	DPC	36	20	20	17	28	5	23	-
	MP&L	36	45	40	61	47	-	-	-
	USBR	84	118	91	127	107	145	109	118
	ISP	21	28	22	30	23	32	15	-
	OTPC	2	2	3	19	-	-	15	-
	UPA	-	-	-	-	-	-	11	-
	NSP	4	40	23	36	18	52	1	-
TOTAL FIRM PURCHASES		183	253	199	290	223	234	174	118
SALES	SYSTEM								
	NSP	-	-	-	-	7	-	-	4
TOTAL FIRM SALES		-	-	-	-	7	-	-	4

All numbers are in megawatts
*Summer: May 1 - October 31; Winter: Nov. 1 - April 30

EXHIBIT 20

PURCHASES	YEAR	1969		1970		1971	
	SEASON*	S	W	S	W	S	W
	SYSTEM						
	DPC	1	6	1	2	-	2
	IPS	-	-	-	-	-	-
	MPC	-	-	-	1	-	4
	LSDP	-	2	-	2	-	1
	NWPS	-	2	-	-	-	1
	ISP	-	6	1	-	-	-
	NSP	-	-	-	-	-	-
	USBR	93	120	109	142	143	156
	OTPC	-	-	-	-	-	-
	IIGE	-	-	-	-	-	-
TOTAL FIRM PURCHASES		94	136	111	147	143	164

SALES	YEAR	1969		1970		1971	
	SEASON*	S	W	S	W	S	W
	SYSTEM						
	NSP	1	1	-	-	2	-
	Hutchinson	-	-	-	6	6	-
	Elk River	-	1	1	1	1	1
	ISP	-	-	-	-	2	-
TOTAL FIRM SALES		1	2	1	7	11	1

All numbers are in megawatts
*Summer: May 1 - October 31; Winter: Nov. 1 - April 30

EXHIBIT 20

PURCHASES	YEAR	1972		1973		1974	
	SEASON*	S	W	S	W	S	W
	SYSTEM						
	DPC	-	-	-	-	2	-
	IPS	-	-	-	-	-	-
	MPC	3	2	8	-	7	10
	LSDP	1	-	-	-	-	4
	NWPS	-	-	-	-	1	-
	ISP	-	7	-	-	-	-
	NSP	-	1	-	9	-	24
	USBR	150	179	140	185	180	144
	OTPC	-	-	-	-	-	7
	IIGE	-	-	-	-	-	16
TOTAL FIRM PURCHASES		154	189	148	194	190	205

SALES	YEAR	1972		1973		1974	
	SEASON*	S	W	S	W	S	W
	SYSTEM						
	NSP	-	-	-	-	-	-
	Hutchinson	-	-	-	-	-	-
	Elk River	1	2	-	-	-	-
	ISP	-	-	-	-	-	-
TOTAL FIRM SALES		1	2	-	-	-	-

All numbers are in megawatts
*Summer: May 1 - October 31; Winter: Nov. 1 - April 30

EXHIBIT 20

PURCHASES	YEAR	1975		1976		1977	
	SEASON*	S	W	S	W	S	W
	SYSTEM						
	LSDP	17	-	-	-	-	-
	IPL	21	-	-	-	-	-
	Willmar	-	-	-	-	-	-
	USBR	132	297	169	331	111	117
	NSP	-	20	-	-	-	-
TOTAL FIRM PURCHASES		170	317	169	331	111	117

All numbers are in megawatts
*Summer: May 1 - October 31; Winter: Nov. 1 - April 30

TOTAL FIRM SALES

None for the years 1975 to 1990.

EXHIBIT 20

	YEAR	1978		1979		1980	
	SEASON*	S	W	S	W	S	W
PURCHASES	SYSTEM						
	IPL	-	-	-	-	-	-
	Willmar	-	-	-	-	-	-
	USBR	91	117	91	117	91	117
	NSP	-	-	-	-	-	-
TOTAL FIRM PURCHASES		91	117	91	117	91	117

All numbers are in megawatts
*Summer: May 1 - October 31; Winter: Nov. 1 - April 30

EXHIBIT 20

	YEAR	1981		1982		1983	
	SEASON*	S	W	S	W	S	W
PURCHASES	SYSTEM						
	USBR	91	117	91	117	91	117
TOTAL FIRM PURCHASES		91	117	91	117	91	117

All numbers are in megawatts
*Summer: May 1 - October 31; Winter: Nov. 1 - April 30

EXHIBIT 20

	YEAR	1984		1985		1986	
	SEASON*	S	W	S	W	S	W
PURCHASES	SYSTEM						
	USBR	91	117	91	117	91	117
TOTAL FIRM PURCHASES		91	117	91	117	91	117

All numbers are in megawatts
*Summer: May 1 - October 31; Winter: Nov. 1 - April 30

EXHIBIT 20

	YEAR	1987		1988		1989		1990	
	SEASON*	S	W	S	W	S	W	S	W
PURCHASES	SYSTEM								
	USBR	91	117	91	117	91	117	91	117
TOTAL FIRM PURCHASES		91	117	91	117	91	117	91	117

All numbers are in megawatts
*Summer: May 1 - October 31; Winter: Nov. 1 - April 30

EXHIBIT 21
CPA SEASONAL PARTICIPATION PURCHASES AND SEASONAL PARTICIPATION SALES
EA 636 (c)

PURCHASES (MW)							SALES (MW)
Year		DPC	MPC	Year		DPC	
1964	S	0		1978	S	170	
	W	0			W	170	
1965	S	0		1979	S	170	
	W	0			W	170	
1966	S	0		1980	S	170	None
	W	0			W	170	for
							1964
1967	S	0		1981	S	170	through
	W	0			W	170	1990
1968	S	0		1982	S	170	
	W	0			W	170	
1969	S	0		1983	S	170	
	W	253			W	170	
1970	S	253		1984	S	170	
	W	241			W	170	
1971	S	241		1985	S	170	
	W	240			W	170	
1972	S	240		1986	S	170	
	W	235			W	170	
1973	S	235		1987	S	170	
	W	231			W	170	
1974	S	231		1988	S	170	
	W	202			W	170	
1975	S	202		1989	S	170	
	W	170	1		W	170	
1976	S	170		1990	S	170	
	W	170			W	170	
1977	S	170					
	W	170					

EXHIBIT 22

UPA - SEASONAL PARTICIPATION PURCHASES
AND SEASONAL PARTICIPATION SALES (MW)
EA 636 (c)

PURCHASES	YEAR	1965-1968		1969		1970		1971	
	SEASON*	S	W	S	W	S	W	S	W
	SYSTEM								
	IPS	-	-	-	-	-	-	-	1
	DPC	-	-	-	-	-	-	-	13
	MPC	-	-	-	-	-	-	-	6
	ISP	-	-	-	-	-	-	-	-
	NWPS	-	-	-	-	-	-	-	-
	NSP	-	-	-	-	-	-	3	1
	OTPC	-	-	-	-	-	1	-	3
	MDU	-	-	-	-	-	-	-	-
	LSDP	-	-	-	-	-	-	-	-
	BEPC	-	-	-	-	-	-	-	-
TOTAL PARTICIPATION PURCHASES		-	-	-	-	-	1	3	24

SALES	YEAR	1965-1968		1969		1970		1971	
	SEASON*	S	W	S	W	S	W	S	W
	SYSTEM								
	MP&L	-	-	-	-	-	-	4	-
	ISP	-	-	-	-	-	-	-	-
	NSP	-	-	-	-	-	-	2	-
	OTPC	-	-	-	-	-	-	-	-
TOTAL PARTICIPATION SALES		-	-	-	-	-	-	6	-

* Summer: May 1 - Oct. 31; Winter: Nov. 1 - Apr. 30
All numbers are in megawatts

EXHIBIT 22

PURCHASES	SYSTEM	1972 S	1972 W	1973 S	1973 W	1974 S	1974 W
	IPS	-	-	-	-	4	-
	DPC	3	4	22	3	22	-
	MPC	-	3	-	39	23	21
	ISP	-	2	-	-	-	-
	NWPS	-	-	-	9	-	-
	NSP	-	8	-	-	-	27
	OTPC	-	-	-	-	-	-
	MDU	-	-	2	5	-	2
	LSDP	-	-	-	-	2	-
	BEPC	-	-	-	-	10	22
TOTAL PARTICIPATION PURCHASES		3	17	24	56	61	72

SALES	SYSTEM	1972 S	1972 W	1973 S	1973 W	1974 S	1974 W
	MP&L	-	-	-	-	-	-
	ISP	3	-	-	-	-	-
	NSP	-	-	-	-	-	-
	OTPC	-	-	-	-	10	7
TOTAL PARTICIPATION SALES		3	-	-	-	10	7

* Summer: May 1 - Oct. 31; Winter: Nov. 1 - Apr. 30
All numbers are in megawatts

EXHIBIT 22

PURCHASES	YEAR	1975		1976		1977	
	SEASON*	S	W	S	W	S	W
	SYSTEM						
	DPC	26	-	-	-	-	-
	MPC	56	30	-	35	-	40
	MDU	8	34	6	-	5	-
	NSP	-	23	-	-	-	-
	NWPS	-	34	10	20	10	10
	OTPC	17	17	11	-	25	-
TOTAL PARTICIPATION POWER PURCHASES		107	138	27	55	40	50

SALES	YEAR	1975		1976		1977	
	SEASON*	S	W	S	W	S	W
	SYSTEM						
	Willmar	2	2	2	3	3	3
TOTAL PARTICIPATION SALES		2	2	2	3	3	3

* Summer: May 1 - Oct. 31; Winter: Nov. 1 - Apr. 30
All numbers are in megawatts

EXHIBIT 22

PURCHASES	YEAR	1978		1979		1980	
	SEASON*	S	W	S	W	S	W
	SYSTEM						
	DPC	-	-	-	-	-	-
	MPC	-	-	-	-	-	-
	MDU	-	-	-	-	-	-
	NSP	-	-	-	-	-	-
	NWPS	-	-	-	-	-	-
	OTPC	-	-	-	-	-	-
TOTAL PARTICIPATION POWER PURCHASES		-	-	-	-	-	-

SALES	YEAR	1978		1979		1980	
	SEASON*	S	W	S	W	S	W
	SYSTEM						
	Willmar	3	5	5	8	8	-
TOTAL PARTICIPATION SALES		3	5	5	8	8	-

* Summer: May 1 - Oct. 31; Winter: Nov. 1 - Apr. 30
All numbers are in megawatts

EXHIBIT 22

YEAR		1981 - 1990	
SEASON*		S	W
PURCHASES	SYSTEM		
	IPS	-	-
	DPC	-	-
	MPC	-	-
	ISP	-	-
	NWPS	-	-
	NSP	-	-
	OTPC	-	-
	MDU	-	-
	LSDP	-	-
	BEPC	-	-
TOTAL PARTICIPATION PURCHASES		-	-

SALES

YEAR		1981 - 1990	
SEASON*		S	W
SALES	SYSTEM		
	MP&L	-	-
	ISP	-	-
	NSP	-	-
	OTPC	-	-
TOTAL PARTICIPATION SALES		-	-

All numbers are in megawatts
*Summer: May 1 - October 31; Winter: Nov. 1 - April 30

EXHIBIT 23

COMBINED SEASONAL PARTICIPATION PURCHASES
AND SEASONAL PARTICIPATION SALES (MW)
EA 636 (c)

	YEAR	1965 - 1968		1969		1970		1971	
	SEASON*	S	W	S	W	S	W	S	W
PURCHASES	SYSTEM								
	IPS	-	-	-	-	-	-	-	1
	DPC	-	-	-	253	253	241	241	253
	MPC	-	-	-	-	-	-	-	6
	ISP	-	-	-	-	-	-	-	-
	NWPS	-	-	-	-	-	-	-	-
	NSP	-	-	-	-	-	-	3	1
	OTPC	-	-	-	-	-	1	-	3
	MDU	-	-	-	-	-	-	-	-
	LSDP	-	-	-	-	-	-	-	-
	BEPC	-	-	-	-	-	-	-	-
TOTAL PARTICIPATION PURCHASES		-	-	-	253	253	242	244	264

	YEAR	1965 - 1968		1969		1970		1971	
	SEASON*	S	W	S	W	S	W	S	W
SALES	SYSTEM								
	MP&L	-	-	-	-	-	-	4	-
	ISP	-	-	-	-	-	-	-	-
	NSP	-	-	-	-	-	-	2	-
	OTPC	-	-	-	-	-	-	-	-
TOTAL PARTICIPATION SALES		-	-	-	-	-	-	6	-

All numbers are in megawatts
*Summer: May 1 - October 31; Winter: Nov. 1 - April 30

EXHIBIT 23

	YEAR	1972		1973		1974	
	SEASON*	S	W	S	W	S	W
PURCHASES	SYSTEM						
	IPS	-	-	-	-	4	-
	DPC	243	239	257	234	253	202
	MPC	-	3	-	39	23	21
	ISP	-	2	-	-	-	-
	NWPS	-	-	-	9	-	-
	NSP	-	8	-	-	-	27
	OTPC	-	-	-	-	-	-
	MDU	-	-	2	5	-	2
	LSDP	-	-	-	-	2	-
	BEPC	-	-	-	-	10	22
TOTAL PARTICIPATION PURCHASES		243	252	259	287	292	274

	YEAR	1972		1973		1974	
	SEASON*	S	W	S	W	S	W
SALES	SYSTEM						
	MP&L	-	-	-	-	-	-
	ISP	3	-	-	-	-	-
	NSP	-	-	-	-	-	-
	OTPC	-	-	-	-	10	7
TOTAL PARTICIPATION SALES		3	-	-	-	10	7

All numbers are in megawatts
*Summer: May 1 - October 31; Winter: Nov. 1 - April 30

EXHIBIT 23

PURCHASES	YEAR	1975		1976		1977	
	SEASON*	S	W	S	W	S	W
	SYSTEM						
	DPC	228	170	170	170	170	170
	MPC	56	31	-	35	-	40
	MDU	8	34	6	-	5	-
	NSP	-	23	-	-	-	-
	NWPS	-	34	10	20	10	10
	OTPC	17	17	11	-	25	-
TOTAL PARTICIPATION POWER PURCHASES		309	309	197	225	210	220

SALES	YEAR	1975		1976		1977	
	SEASON*	S	W	S	W	S	W
	SYSTEM						
	Willmar	2	2	2	3	3	3
TOTAL PARTICIPATION SALES		2	2	2	3	3	3

All numbers are in megawatts
*Summer: May 1 - October 31; Winter: Nov. 1 - April 30

EXHIBIT 23

	YEAR	1978		1979		1980		1981 - 1990	
	SEASON*	S	W	S	W	S	W	S	W
PURCHASES	SYSTEM								
	DPC	170	170	170	170	170	170	170	170
	MPC	-	-	-	-	-	-	-	-
	MDU	-	-	-	-	-	-	-	-
	NSP	-	-	-	-	-	-	-	-
	NWPS	-	-	-	-	-	-	-	-
	OTPC	-	-	-	-	-	-	-	-
TOTAL PARTICIPATION POWER PURCHASES		170	170	170	170	170	170	170	170

	YEAR	1978		1979		1980		1981 - 1990	
	SEASON*	S	W	S	W	S	W	S	W
SALES	SYSTEM								
	Willmar	3	5	5	8	8	-	-	-
TOTAL PARTICIPATION SALES		3	5	5	8	8	-	-	-

All numbers are in megawatts
*Summer: May 1 - October 31; Winter: Nov. 1 - April 30

EXHIBIT 24

CPA'S LOAD AND GENERATION CAPACITY DATA WITHOUT THE PROPOSED FACILITY

EA636 (d)

		sum 1975	win 1975	sum 1976	win 1976	sum 1977	win 1977	sum 1978	win 1978
(1)	Seasonal System Demand	332	428	364	470	400	517	439	561
(2)	Annual System Demand	391	428	428	470	470	517	517	561
(3)	Total Seasonal Firm Purchases	157	291	164	325	106	111	86	111
(4)	Total Seasonal Firm Sales	0	0	0	0	0	0	0	0
(5)	Seasonal Adjusted Net Demand (1 - 3 + 4)	175	137	200	145	294	406	353	450
(6)	Annual Adjusted Net Demand (2 - 3 + 4)	234	137	264	145	364	406	431	450
(7)	Net Generating Capacity	11	16	16	16	16	16	16	16
(8)	Total Seasonal Participation Purchases	202	171	170	170	170	170	170	170
(9)	Total Seasonal Participation Sales	0	0	0	0	0	0	0	0
(10)	Adjusted Net Capability (7 + 8 - 9)	213	187	186	186	186	186	186	186
(11)	Net Reserve Capacity Obligation (6 x 15%)	35	21	40	22	55	61	65	68
(12)	Total Firm Capacity Obligation (5 + 11)	210	158	240	167	349	467	418	518
(13)	Surplus (+) or Deficit (-) Capacity (10 - 12)	3	29	-54	19	-163	-281	-232	-332

EXHIBIT 24
CPA'S LOAD AND GENERATION CAPACITY DATA WITHOUT THE PROPOSED FACILITY
EA636 (d)

		sum 1979	win 1979	sum 1980	win 1980	sum 1981	win 1981	sum 1982	win 1982
(1)	Seasonal System Demand	477	609	518	662	563	720	612	784
(2)	Annual System Demand	561	609	609	662	662	720	720	784
(3)	Total Seasonal Firm Purchases	86	111	86	111	86	111	86	111
(4)	Total Seasonal Firm Sales	0	0	0	0	0	0	0	0
(5)	Seasonal Adjusted Net Demand (1 - 3 + 4)	391	498	432	551	477	609	526	673
(6)	Annual Adjusted Net Demand (2 - 3 + 4)	475	498	523	551	576	609	634	673
(7)	Net Generating Capacity	16	16	16	16	16	16	16	16
(8)	Total Seasonal Participation Purchases	170	170	170	170	170	170	170	170
(9)	Total Seasonal Participation Sales	0	0	0	0	0	0	0	0
(10)	Adjusted Net Capability (7 + 8 - 9)	186	186	186	186	186	186	186	186
(11)	Net Reserve Capacity Obligation (6 x 15%)	71	75	79	83	86	91	95	101
(12)	Total Firm Capactiy Obligation (5 + 11)	462	573	511	634	563	700	621	774
(13)	Surplus (+) or Deficit (-) Capacity (10 - 12)	-276	-387	-325	-448	-377	-514	-435	-588

EXHIBIT 24
CPA'S LOAD AND GENERATION CAPACITY DATA WITHOUT THE PROPOSED FACILITY
EA636 (d)

		sum 1983	win 1983	sum 1984	win 1984	sum 1985	win 1985	sum 1986	win 1986
(1)	Seasonal System Demand	666	855	727	933	793	1018	865	1114
(2)	Annual System Demand	784	855	855	933	933	1018	1018	1114
(3)	Total Seasonal Firm Purchases	86	111	86	111	86	111	86	111
(4)	Total Seasonal Firm Sales	0	0	0	0	0	0	0	0
(5)	Seasonal Adjusted Net Demand (1 - 3 + 4)	580	744	641	822	707	907	779	1003
(6)	Annual Adjusted Net Demand (2 - 3 + 4)	698	744	769	822	847	907	932	1003
(7)	Net Generating Capacity	16	16	16	16	16	16	16	16
(8)	Total Seasonal Participation Purchases	170	170	170	170	170	170	170	170
(9)	Total Seasonal Participation Sales	0	0	0	0	0	0	0	0
(10)	Adjusted Net Capability (7 + 8 - 9)	186	186	186	186	186	186	186	186
(11)	Net Reserve Capacity Obligation (5 + 11)	105	112	115	123	127	136	140	151
(12)	Total Firm Capacity Obligation (5 + 11)	685	856	756	945	834	1043	919	1154
(13)	Surplus (+) or Deficit (-) Capacity (10 - 12)	-499	-670	-570	-759	-648	-857	-733	-968

EXHIBIT 24
CPA'S LOAD AND GENERATION CAPACITY DATA WITHOUT THE PROPOSED FACILITY
EA636 (d)

		sum 1987	win 1987	sum 1988	win 1988	sum 1989	win 1989	sum 1990	win 1990
(1)	Seasonal System Demand	947	1217	1034	1333	1133	1461	1242	1601
(2)	Annual System Demand	1114	1217	1217	1333	1333	1461	1461	1601
(3)	Total Seasonal Firm Purchases	86	111	86	111	86	111	86	111
(4)	Total Seasonal Firm Sales	0	0	0	0	0	0	0	0
(5)	Seasonal Adjusted Net Demand (1 - 3 + 4)	861	1106	948	1222	1047	1350	1156	1490
(6)	Annual Adjusted Net Demand (2 - 3 + 4)	1028	1106	1131	1222	1247	1350	1375	1490
(7)	Net Generating Capacity	16	16	16	16	16	16	16	16
(8)	Total Seasonal Participation Purchases	170	170	170	170	170	170	170	170
(9)	Total Seasonal Participation Sales	0	0	0	0	0	0	0	0
(10)	Adjusted Net Capability (7 + 8 - 9)	186	186	186	186	186	186	186	186
(11)	Net Reserve Capacity Obligation (6 x 15%)	154	166	170	183	187	203	206	224
(12)	Total Firm Capacity Obligation (5+ 11)	1015	1272	1118	1405	1234	1553	1362	1714
(13)	Surplus (+) or Deficit (-) Capacity (10 - 12)	-829	-1086	-932	-1219	-1048	-1367	-1176	-1528

EXHIBIT 25

UPA - LOAD AND GENERATION CAPACITY DATA
WITHOUT PROPOSED FACILITY (MW)
EA 636 (d)

Year	1975		1976		1977	
Season*	S	W	S	W	S	W
(1) Seasonal System Demand	302	345	328	378	360	414
(2) Annual System Demand	321	345	345	378	378	414
(3) Total Firm Purchases	13	26	5	6	5	6
(4) Total Firm Sales	-	-	-	-	-	-
(5) Seasonal Adjusted Net Demand (1-3+4)	289	319	323	372	355	408
(6) Annual Adjusted Net Demand (2-3+4)	308	319	340	372	373	408
(7) Net Generating Capability	237	237	237	237	237	237
(8) Total Participation Purchases	107	138	27	55	40	50
(9) Total Participation Sales	2	2	2	3	3	3
(10) Adjusted Net Capability (7+8-9)	342	373	262	289	274	284
(11) Net Reserve Capacity Obligation (6x15%)**	46	48	51	56	56	61
(12) Total Firm Capacity Obligation (5+11)	335	367	374	428	411	469
(13) Surplus or (Deficit) Capacity (10-12)	(7)	(6)	(112)	(139)	(137)	(185)

All Numbers Are in Megawatts
* Summer, May 1 - October 31; Winter, November 1 - April 30
**For a Predominantly Hydro System (6x10%)

EXHIBIT 25

	Year	1978		1979		1980	
	Season*	S	W	S	W	S	W
(1)	Seasonal System Demand	395	470	452	535	516	588
(2)	Annual System Demand	414	470	470	535	535	588
(3)	Total Firm Purchases	5	6	5	6	5	6
(4)	Total Firm Sales	-	-	-	-	-	-
(5)	Seasonal Adjusted Net Demand (1-3+4)	390	464	447	529	511	582
(6)	Annual Adjusted Net Demand (2-3+4)	409	464	465	529	530	582
(7)	Net Generating Capability	237	237	237	237	237	237
(8)	Total Participation Purchases	-	-	-	-	-	-
(9)	Total Participation Sales	3	5	5	8	8	-
(10)	Adjusted Net Capability (7+8-9)	234	232	232	229	229	237
(11)	Net Reserve Capacity Obligation (6x15%)**	61	70	70	79	79	87
(12)	Total Firm Capacity Obligation (5+11)	451	534	517	608	590	669
(13)	Surplus or (Deficit) Capacity (10-12)	(217)	(302)	(285)	(379)	(361)	(432)

All Numbers Are in Megawatts
* Summer, May 1 - October 31; Winter, November 1 - April 30
**For a Predominantly Hydro System (6x10%)

EXHIBIT 25

	Year	1981		1982		1983	
	Season*	S	W	S	W	S	W
(1)	Seasonal System Demand	567	646	622	710	698	780
(2)	Annual System Demand	588	646	646	710	710	780
(3)	Total Firm Purchases	5	6	5	6	5	6
(4)	Total Firm Sales	-	-	-	-	-	-
(5)	Seasonal Adjusted Net Demand (1-3+4)	561	640	716	704	693	774
(6)	Annual Adjusted Net Demand (2-3+4)	583	640	641	704	705	774
(7)	Net Generating Capability	237	237	237	237	237	237
(8)	Total Participation Purchases	-	-	-	-	-	-
(9)	Total Participation Sales	-	-	-	-	-	-
(10)	Adjusted Net Capability (7+8-9)	237	237	237	237	237	237
(11)	Net Reserve Capacity Obligation (6x15%)**	87	96	96	106	106	116
(12)	Total Firm Capacity Obligation (5+11)	649	736	713	810	799	890
(13)	Surplus or (Deficit) Capacity (10-12)	(412)	(499)	(476)	(573)	(562)	(653)

All Numbers Are in Megawatts
* Summer, May 1 - October 31; Winter, November 1 - April 30
**For a Predominantly Hydro System (6x10%)

EXHIBIT 25

	Year	1984		1985		1986	
	Season*	S	W	S	W	S	W
(1)	Seasonal System Demand	767	857	844	944	928	1038
(2)	Annual System Demand	780	857	857	944	944	1038
(3)	Total Firm Purchases	5	6	5	6	5	6
(4)	Total Firm Sales	-	-	-	-	-	-
(5)	Seasonal Adjusted Net Demand (1-3+4)	762	851	839	938	923	1032
(6)	Annual Adjusted Net Demand (2-3+4)	775	851	852	938	939	1032
(7)	Net Generating Capability	237	237	237	237	237	237
(8)	Total Participation Purchases	-	-	-	-	-	-
(9)	Total Participation Sales	-	-	-	-	-	-
(10)	Adjusted Net Capability (7+8-9)	237	237	237	237	237	237
(11)	Net Reserve Capacity Obligation (6x15%)**	116	128	128	141	141	155
(12)	Total Firm Capacity Obligation (5+11)	878	979	967	1079	1064	1187
(13)	Surplus or (Deficit) Capacity (10-12)	(641)	(742)	(730)	(842)	(827)	(950)

All Numbers Are in Megawatts

* Summer, May 1 - October 31; Winter, November 1 - April 30

**For a Predominantly Hydro System (6x10%)

EXHIBIT 25

	Year	1987		1988		1989	
	Season*	S	W	S	W	S	W
(1)	Seasonal System Demand	1022	1144	1125	1260	1237	1386
(2)	Annual System Demand	1038	1144	1144	1260	1260	1386
(3)	Total Firm Purchases	5	6	5	6	5	6
(4)	Total Firm Sales	-	-	-	-	-	-
(5)	Seasonal Adjusted Net Demand (1-3+4)	1017	1138	1120	1254	1232	1380
(6)	Annual Adjusted Net Demand (2-3+4)	1033	1138	1139	1254	1255	1380
(7)	Net Generating Capability	237	237	237	237	237	237
(8)	Total Participation Purchases	-	-	-	-	-	-
(9)	Total Participation Sales	-	-	-	-	-	-
(10)	Adjusted Net Capability (7+8-9)	237	237	237	237	237	237
(11)	Net Reserve Capacity Obligation (6x15%)**	155	171	171	188	188	207
(12)	Total Firm Capacity Obligation (5+11)	1172	1309	1291	1442	1420	1587
(13)	Surplus or (Deficit) Capacity (10-12)	(935)	(1072)	(1054)	(1205)	(1183)	(1350)

All Numbers Are in Megawatts
* Summer, May 1 - October 31; Winter, November 1 - April 30
**For a Predominantly Hydro System (6x10%)

EXHIBIT 25

	Year	1990	
	Season*	S	W
(1)	Seasonal System Demand	1364	1530
(2)	Annual System Demand	1386	1530
(3)	Total Firm Purchases	5	6
(4)	Total Firm Sales	-	-
(5)	Seasonal Adjusted Net Demand (1-3+4)	1359	1524
(6)	Annual Adjusted Net Demand (2-3+4)	1381	1524
(7)	Net Generating Capability	237	237
(8)	Total Participation Purchases	-	-
(9)	Total Participation Sales	-	-
(10)	Adjusted Net Capability (7+8-9)	237	237
(11)	Net Reserve Capacity Obligation (6x15%)**	207	228
(12)	Total Firm Capacity Obligation (5+11)	1566	1752
(13)	Surplus or (Deficit) Capacity (10-12)	(1329)	(1515)

All Numbers Are in Megawatts
* Summer, May 1 - October 31; Winter, November 1 - April 30
**For a Predominantly Hydro System (6x10%)

EXHIBIT 26

COMBINED LOAD AND GENERATION CAPACITY DATA
WITHOUT PROPOSED FACILITY (MW)
EA 636 (d)

Year	1975		1976		1977	
Season*	S	W	S	W	S	W
(1) Seasonal System Demand	634	773	692	848	760	931
(2) Annual System Demand	712	773	773	848	848	931
(3) Total Firm Purchases	170	317	169	331	111	117
(4) Total Firm Sales	-	-	-	-	-	-
(5) Seasonal Adjusted Net Demand (1-3+4)	464	456	523	517	649	814
(6) Annual Adjusted Net Demand (2-3+4)	542	456	604	517	737	814
(7) Net Generating Capability	248	253	253	253	253	253
(8) Total Participation Purchases	309	309	197	225	210	220
(9) Total Participation Sales	2	2	2	3	3	3
(10) Adjusted Net Capability (7+8-9)	555	560	448	475	460	470
(11) Net Reserve Capacity Obligation (6x15%)**	81	69	91	78	111	122
(12) Total Firm Capacity Obligation (5+11)	545	525	614	595	760	936
(13) Surplus or (Deficit) Capacity (10-12)	10	35	(166)	(120)	(300)	(466)

All Numbers Are in Megawatts
* Summer, May 1 - October 31; Winter, November 1 - April 30
**For a Predominantly Hydro System (6x10%)

EXHIBIT 26

	Year	1978		1979		1980	
	Season*	S	W	S	W	S	W
(1)	Seasonal System Demand	834	1031	929	1144	1034	1250
(2)	Annual System Demand	931	1031	1031	1144	1144	1250
(3)	Total Firm Purchases	91	117	91	117	91	117
(4)	Total Firm Sales	-	-	-	-	-	-
(5)	Seasonal Adjusted Net Demand (1-3+4)	743	914	838	1027	943	1133
(6)	Annual Adjusted Net Demand (2-3+4)	840	914	940	1027	1053	1133
(7)	Net Generating Capability	253	253	253	253	253	253
(8)	Total Participation Purchases	170	170	170	170	170	170
(9)	Total Participation Sales	3	5	5	8	8	-
(10)	Adjusted Net Capability (7+8-9)	420	418	418	415	415	423
(11)	Net Reserve Capacity Obligation (6x15%)**	126	138	141	154	158	170
(12)	Total Firm Capacity Obligation (5+11)	869	1052	979	1181	1101	1303
(13)	Surplus or (Deficit) Capacity (10-12)	(449)	(634)	(561)	(766)	(686)	(880)

All Numbers Are in Megawatts
* Summer, May 1 - October 31; Winter, November 1 - April 30
**For a Predominantly Hydro System (6x10%)

EXHIBIT 26

	Year	1981		1982		1983	
	Season*	S	W	S	W	S	W
(1)	Seasonal System Demand	1130	1366	1234	1494	1364	1635
(2)	Annual System Demand	1250	1366	1366	1494	1494	1635
(3)	Total Firm Purchases	91	117	91	117	91	117
(4)	Total Firm Sales	-	-	-	-	-	-
(5)	Seasonal Adjusted Net Demand (1-3+4)	1039	1249	1143	1377	1273	1518
(6)	Annual Adjusted Net Demand (2-3+4)	1159	1249	1275	1377	1403	1518
(7)	Net Generating Capability	253	253	253	253	253	253
(8)	Total Participation Purchases	170	170	170	170	170	170
(9)	Total Participation Sales	-	-	-	-	-	-
(10)	Adjusted Net Capability (7+8-9)	423	423	423	423	423	423
(11)	Net Reserve Capacity Obligation (6x15%)**	173	187	191	207	211	228
(12)	Total Firm Capacity Obligation (5+11)	1212	1436	1334	1584	1484	1746
(13)	Surplus or (Deficit) Capacity (10-12)	(789)	(1013)	(911)	(1161)	(1061)	(1323)

All Numbers Are in Megawatts
* Summer, May 1 - October 31; Winter, November 1 - April 30
**For a Predominantly Hydro System (6x10%)

EXHIBIT 26

	Year	1984		1985		1986	
	Season*	S	W	S	W	S	W
(1)	Seasonal System Demand	1494	1790	1637	1962	1793	2152
(2)	Annual System Demand	1635	1790	1790	1962	1962	2152
(3)	Total Firm Purchases	91	117	91	117	91	117
(4)	Total Firm Sales	-	-	-	-	-	-
(5)	Seasonal Adjusted Net Demand (1-3+4)	1403	1673	1546	1845	1702	2035
(6)	Annual Adjusted Net Demand (2-3+4)	1544	1673	1699	1845	1871	2035
(7)	Net Generating Capability	253	253	253	253	253	253
(8)	Total Participation Purchases	170	170	170	170	170	170
(9)	Total Participation Sales	-	-	-	-	-	-
(10)	Adjusted Net Capability (7+8-9)	423	423	423	423	423	423
(11)	Net Reserve Capacity Obligation (6x15%)**	231	251	255	277	281	306
(12)	Total Firm Capacity Obligation (5+11)	1634	1924	1801	2122	1983	2341
(13)	Surplus or (Deficit) Capacity (10-12)	(1211)	(1501)	(1378)	(1699)	(1560)	(1918)

All Numbers Are in Megawatts
* Summer, May 1 - October 31; Winter, November 1 - April 30
**For a Predominantly Hydro System (6x10%)

EXHIBIT 26

	Year	1987		1988		1989	
	Season*	S	W	S	W	S	W
(1)	Seasonal System Demand	1969	2361	2159	2593	2370	2847
(2)	Annual System Demand	2152	2361	2361	2593	2593	2847
(3)	Total Firm Purchases	91	117	91	117	91	117
(4)	Total Firm Sales	-	-	-	-	-	-
(5)	Seasonal Adjusted Net Demand (1-3+4)	1878	2244	2068	2476	2279	2730
(6)	Annual Adjusted Net Demand (2-3+4)	2061	2244	2270	2476	2502	2730
(7)	Net Generating Capability	253	253	253	253	253	253
(8)	Total Participation Purchases	170	170	170	170	170	170
(9)	Total Participation Sales	-	-	-	-	-	-
(10)	Adjusted Net Capability (7+8-9)	423	423	423	423	423	423
(11)	Net Reserve Capacity Obligation (6x15%)**	309	337	341	371	375	410
(12)	Total Firm Capacity Obligation (5+11)	2187	2581	2409	2847	2654	3140
(13)	Surplus or (Deficit) Capacity (10-12)	(1764)	(2158)	(1981)	(2424)	(2231)	(2717)

All Numbers Are in Megawatts
* Summer, May 1 - October 31; Winter, November 1 - April 30
**For a Predominantly Hydro System (6x10%)

EXHIBIT 26

Year	1990	
Season*	S	W
(1) Seasonal System Demand	2606	3131
(2) Annual System Demand	2847	3131
(3) Total Firm Purchases	91	117
(4) Total Firm Sales	-	-
(5) Seasonal Adjusted Net Demand (1-3+4)	2515	3014
(6) Annual Adjusted Net Demand (2-3+4)	2756	3014
(7) Net Generating Capability	253	253
(8) Total Participation Purchases	170	170
(9) Total Participation Sales	-	-
(10) Adjusted Net Capability (7+8-9)	423	423
(11) Net Reserve Capacity Obligation (6x15%)**	413	452
(12) Total Firm Capacity Obligation (5+11)	2928	3466
(13) Surplus or (Deficit) Capacity (10-12)	(2505)	(3043)

All Numbers Are in Megawatts

* Summer, May 1 - October 31; Winter, November 1 - April 30

**For a Predominantly Hydro System (6x10%)

EXHIBIT 27

CPA LOAD CAPACITY AND RESERVE AS PROJECTED WITH THE PROPOSED FACILITY

EA636 (e)

		sum 1975	win 1975	sum 1976	win 1976	sum 1977	win 1977	sum 1978	win 1978
(1)	Seasonal System Demand	332	428	364	470	400	517	439	561
(2)	Annual System Demand	391	428	428	470	470	517	517	561
(3)	Total Seasonal Firm Purchases	157	291	164	325	106	111	86	111
(4)	Total Seasonal Firm Sales	0	0	0	0	0	0	0	0
(5)	Seasonal Adjusted Net Demand (1 - 3 + 4)	175	137	200	145	294	406	353	450
(6)	Annual Adjusted Net Demand (2 - 3 + 4)	234	137	264	145	364	406	431	450
(7)	Net Generating Capacity	11	16	16	16	16	16	16	271
(8)	Total Seasonal Participation Purchases	202	171	170	170	170	170	170	170
(9)	Total Seasonal Participation Sales	0	0	0	0	0	0	0	0
(10)	Adjusted Net Capability (7 + 8 - 9)	213	187	186	186	186	186	186	441
(11)	Net Reserve Capacity Obligation (6 x 15%)	35	21	40	22	55	61	65	68
(12)	Total Firm Capacity Obligation (5 + 11)	210	158	240	167	349	467	418	518
(13)	Surplus (+) or Deficit (-) Capacity (10 - 12)	3	29	-54	19	-163	-281	-232	-77

EXHIBIT 27

CPA LOAD CAPACITY AND RESERVE AS PROJECTED WITH THE PROPOSED FACILITY

EA636 (e)

		sum 1979	win 1979	sum 1980	win 1980	sum 1981	win 1981	sum 1982	win 1982
(1)	Seasonal System Demand	477	609	518	662	563	720	612	784
(2)	Annual System Demand	561	609	609	662	662	720	720	784
(3)	Total Seasonal Firm Purchases	86	111	86	111	86	111	86	111
(4)	Total Seasonal Firm Sales	0	0	0	0	0	0	0	0
(5)	Seasonal Adjusted Net Demand (1 - 3 + 4)	391	498	432	551	477	609	526	673
(6)	Annual Adjusted Net Demand (2 - 3 + 4)	475	498	523	551	576	609	634	673
(7)	Net Generating Capacity	270	522	521	522	521	522	521	522
(8)	Total Seasonal Participation Purchases	170	170	170	170	170	170	170	170
(9)	Total Seasonal Participation Sales	0	0	0	0	0	0	0	0
(10)	Adjusted Net Capability (7 + 8 - 9)	440	692	691	692	691	692	691	692
(11)	Net Reserve Capacity Obligation (6 x 15%)	71	75	79	83	86	91	95	101
(12)	Total Firm Capacity Obligation (5 + 11)	462	573	511	634	563	700	621	774
(13)	Surplus (+) or Deficit (-) Capacity (10 - 12)	-22	119	180	58	128	-8	70	-82

EXHIBIT 27
CPA LOAD CAPACITY AND RESERVE AS PROJECTED WITH THE PROPOSED FACILITY
EA636 (e)

		sum 1983	win 1983	sum 1984	win 1984	sum 1985	win 1985	sum 1986	win 1986
(1)	Seasonal System Demand	666	855	727	933	793	1018	865	1114
(2)	Annual System Demand	784	855	855	933	933	1018	1018	1114
(3)	Total Seasonal Firm Purchases	86	111	86	111	86	111	86	111
(4)	Total Seasonal Firm Sales	0	0	0	0	0	0	0	0
(5)	Seasonal Adjusted Net Demand (1 - 3 + 4)	580	744	641	822	707	907	779	1003
(6)	Annual Adjusted Net Demand (2 - 3 + 4)	698	744	769	822	847	907	932	1003
(7)	Net Generating Capacity	521	522	521	522	521	522	521	522
(8)	Total Seasonal Participation Purchases	170	170	170	170	170	170	170	170
(9)	Total Seasonal Participation Sales	0	0	0	0	0	0	0	0
(10)	Adjusted Net Capability (7 + 8 - 9)	691	692	691	692	691	692	691	692
(11)	Net Reserve Capacity Obligation (6 x 15%)	105	112	115	123	127	136	140	151
(12)	Total Firm Capacity Obligation (5 + 11)	685	856	756	945	834	1043	919	1154
(13)	Surplus (+) or Deficit (-) Capacity (10 - 12)	6	-164	-65	-253	-143	-351	-228	-462

EXHIBIT 27
CPA LOAD CAPACITY AND RESERVE AS PROJECTED WITH THE PROPOSED FACILITY
EA636 (e)

		sum 1987	win 1987	sum 1988	win 1988	sum 1989	win 1989	sum 1990	win 1990
(1)	Seasonal System Demand	947	1217	1034	1333	1133	1461	1242	1601
(2)	Annual System Demand	1114	1217	1217	1333	1333	1461	1461	1601
(3)	Total Seasonal Firm Purchases	86	111	86	111	86	111	86	111
(4)	Total Seasonal Firm Sales	0	0	0	0	0	0	0	0
(5)	Seasonal Adjusted Net Demand (1 - 3 + 4)	861	1106	948	1222	1047	1350	1156	1490
(6)	Annual Adjusted Net Demand (2 - 3 + 4)	1028	1106	1131	1222	1247	1350	1375	1490
(7)	Net Generating Capacity	521	522	521	522	521	522	521	522
(8)	Total Seasonal Participation Purchases	170	170	170	170	170	170	170	170
(9)	Total Seasonal Participation Sales	0	0	0	0	0	0	0	0
(10)	Adjusted Net Capability (7 + 8 - 9)	691	692	691	692	691	692	691	692
(11)	Net Reserve Capacity Obligation (6 x 15%)	154	166	170	183	187	203	206	224
(12)	Total Firm Capacity Obligation (5+ 11)	1015	1272	1118	1405	1234	1553	1362	1714
(13)	Surplus (+) or Deficit (-) Capacity (10 - 12)	-324	-580	-427	-713	-543	-861	-671	-1022

EXHIBIT 28

UPA - LOAD, CAPACITY AND RESERVE AS PROJECTED
WITH THE PROPOSED FACILITY (MW)
EA 636 (e)

	Year	1975		1976		1977	
	Season*	S	W	S	W	S	W
(1)	Seasonal System Demand	302	345	328	378	360	414
(2)	Annual System Demand	321	345	345	378	378	414
(3)	Total Firm Purchases	13	26	5	6	5	6
(4)	Total Firm Sales	-	-	-	-	-	-
(5)	Seasonal Adjusted Net Demand (1-3+4)	289	319	323	372	355	408
(6)	Annual Adjusted Net Demand (2-3+4)	308	319	340	372	373	408
(7)	Net Generating Capability	237	237	237	237	237	237
(8)	Total Participation Purchases	107	138	27	55	40	50
(9)	Total Participation Sales	2	2	2	3	3	3
(10)	Adjusted Net Capability (7+8-9)	342	373	262	289	274	284
(11)	Net Reserve Capacity Obligation (6x15%) **	46	48	51	56	56	61
(12)	Total Firm Capacity Obligation (5+11)	335	367	374	428	411	469
(13)	Surplus or (Deficit) Capacity (10-12)	(7)	(6)	(112)	(139)	(137)	(185)

All Numbers Are in Megawatts

* Summer, May 1 - October 31; Winter, November 1 - April 30

** For a Predominantly Hydro System (6x10%)

EXHIBIT 28

Year	1978		1979		1980	
Season*	S	W	S	W	S	W
(1) Seasonal System Demand	395	470	452	535	516	588
(2) Annual System Demand	414	470	470	535	535	588
(3) Total Firm Purchases	5	6	5	6	5	6
(4) Total Firm Sales	-	-	-	-	-	-
(5) Seasonal Adjusted Net Demand (1-3+4)	390	464	447	529	511	582
(6) Annual Adjusted Net Demand (2-3+4)	409	464	465	529	530	582
(7) Net Generating Capability	237	452	452	667	667	667
(8) Total Participation Purchases	-	-	-	-	-	-
(9) Total Participation Sales	3	5	5	8	8	-
(10) Adjusted Net Capability (7+8-9)	234	447	447	659	659	667
(11) Net Reserve Capacity Obligation (6x15%)**	61	70	70	79	79	87
(12) Total Firm Capacity Obligation (5+11)	451	534	517	608	590	669
(13) Surplus or (Deficit) Capacity (10-12)	(217)	(87)	(70)	51	69	(2)

All Numbers Are in Megawatts

* Summer, May 1 - October 31; Winter, November 1 - April 30

** For a Predominantly Hydro System (6x10%)

EXHIBIT 28

	Year	1981		1982		1983	
	Season*	S	W	S	W	S	W
(1)	Seasonal System Demand	567	646	622	710	698	780
(2)	Annual System Demand	588	646	646	710	710	780
(3)	Total Firm Purchases	5	6	5	6	5	6
(4)	Total Firm Sales	-	-	-	-	-	-
(5)	Seasonal Adjusted Net Demand (1-3+4)	562	640	617	704	693	774
(6)	Annual Adjusted Net Demand (2-3+4)	583	640	641	704	705	774
(7)	Net Generating Capability	667	667	667	667	667	667
(8)	Total Participation Purchases	-	-	-	-	-	-
(9)	Total Participation Sales	-	-	-	-	-	-
(10)	Adjusted Net Capability (7+8-9)	667	667	667	667	667	667
(11)	Net Reserve Capacity Obligation (6x15%)**	87	96	96	106	106	116
(12)	Total Firm Capacity Obligation (5+11)	649	736	713	810	799	890
(13)	Surplus or (Deficit) Capacity (10-12)	18	(69)	(46)	(143)	(132)	(223)

All Numbers Are in Megawatts

* Summer, May 1 - October 31; Winter, November 1 - April 30

** For a Predominantly Hydro System (6x10%)

EXHIBIT 28

	Year	1984		1985		1986	
	Season*	S	W	S	W	S	W
(1)	Seasonal System Demand	767	857	844	944	928	1038
(2)	Annual System Demand	780	857	857	944	944	1038
(3)	Total Firm Purchases	5	6	5	6	5	6
(4)	Total Firm Sales	-	-	-	-	-	-
(5)	Seasonal Adjusted Net Demand (1-3+4)	762	851	839	938	923	1032
(6)	Annual Adjusted Net Demand (2-3+4)	775	851	852	938	939	1032
(7)	Net Generating Capability	667	667	667	667	667	667
(8)	Total Participation Purchases	-	-	-	-	-	-
(9)	Total Participation Sales	-	-	-	-	-	-
(10)	Adjusted Net Capability (7+8-9)	667	667	667	667	667	667
(11)	Net Reserve Capacity Obligation (6x15%)**	116	128	128	141	141	155
(12)	Total Firm Capacity Obligation (5+11)	878	979	967	1079	1064	1187
(13)	Surplus or (Deficit) Capacity (10-12)	(211)	(312)	(300)	(412)	(397)	(520)

All Numbers Are in Megawatts

* Summer, May 1 - October 31; Winter, November 1 - April 30

** For a Predominantly Hydro System (6x10%)

EXHIBIT 28

	Year	1987		1988		1989	
	Season*	S	W	S	W	S	W
(1)	Seasonal System Demand	1022	1144	1125	1260	1237	1386
(2)	Annual System Demand	1038	1144	1144	1260	1260	1386
(3)	Total Firm Purchases	5	6	5	6	5	6
(4)	Total Firm Sales	-	-	-	-	-	-
(5)	Seasonal Adjusted Net Demand (1-3+4)	1017	1138	1120	1254	1232	1380
(6)	Annual Adjusted Net Demand (2-3+4)	1033	1138	1139	1254	1255	1380
(7)	Net Generating Capability	667	667	667	667	667	667
(8)	Total Participation Purchases	-	-	-	-	-	-
(9)	Total Participation Sales	-	-	-	-	-	-
(10)	Adjusted Net Capability (7+8-9)	667	667	667	667	667	667
(11)	Net Reserve Capacity Obligation (6x15%)**	155	171	171	188	188	207
(12)	Total Firm Capacity Obligation (5+11)	1172	1309	1291	1442	1420	1587
(13)	Surplus or (Deficit) Capacity (10-12)	(505)	(642)	(624)	(775)	(753)	(920)

All Numbers Are in Megawatts
* Summer, May 1 - October 31; Winter, November 1 - April 30
** For a Predominantly Hydro System (6x10%)

EXHIBIT 28

	Year	1990	
	Season*	S	W
(1)	Seasonal System Demand	1364	1530
(2)	Annual System Demand	1386	1530
(3)	Total Firm Purchases	5	6
(4)	Total Firm Sales	-	-
(5)	Seasonal Adjusted Net Demand (1-3+4)	1359	1524
(6)	Annual Adjusted Net Demand (2-3+4)	1381	1524
(7)	Net Generating Capability	667	667
(8)	Total Participation Purchases	-	-
(9)	Total Participation Sales	-	-
(10)	Adjusted Net Capability (7+8-9)	667	667
(11)	Net Reserve Capacity Obligation (6x15%)**	207	228
(12)	Total Firm Capacity Obligation (5+11)	1566	1752
(13)	Surplus or (Deficit) Capacity (10-12)	(899)	(1085)

All Numbers Are in Megawatts

* Summer, May 1 - October 31; Winter, November 1 - April 30

** For a Predominantly Hydro System (6x10%)

EXHIBIT 29

COMBINED LOAD CAPACITY AND RESERVE AS PROJECTED
WITH PROPOSED FACILITY (MW)
EA 636 (e)

Year	1975		1976		1977	
Season*	S	W	S	W	S	W
(1) Seasonal System Demand	634	773	692	848	760	931
(2) Annual System Demand	712	773	773	848	848	931
(3) Total Firm Purchases	170	317	169	331	111	117
(4) Total Firm Sales	-	-	-	-	-	-
(5) Seasonal Adjusted Net Demand (1-3+4)	464	456	523	517	649	814
(6) Annual Adjusted Net Demand (2-3+4)	542	456	604	517	737	814
(7) Net Generating Capability	248	253	253	253	253	253
(8) Total Participation Purchases	309	309	197	225	210	220
(9) Total Participation Sales	2	2	2	3	3	3
(10) Adjusted Net Capability (7+8-9)	555	560	448	475	460	470
(11) Net Reserve Capacity Obligation (6x15%)**	81	69	91	78	111	122
(12) Total Firm Capacity Obligation (5+11)	545	525	614	595	760	936
(13) Surplus or (Deficit) Capacity (10-12)	10	35	(166)	(120)	(300)	(466)

All Numbers Are in Megawatts
* Summer, May 1 - October 31; Winter, November 1 - April 30
**For a Predominantly Hydro System (6x10%)

EXHIBIT 29

Year	1978		1979		1980	
Season*	S	W	S	W	S	W
(1) Seasonal System Demand	834	1031	929	1144	1034	1250
(2) Annual System Demand	931	1031	1031	1144	1144	1250
(3) Total Firm Purchases	91	117	91	117	91	117
(4) Total Firm Sales	-	-	-	-	-	-
(5) Seasonal Adjusted Net Demand (1-3+4)	743	914	838	1027	943	1133
(6) Annual Adjusted Net Demand (2-3+4)	840	914	940	1027	1053	1133
(7) Net Generating Capability	253	723	722	1189	1188	1189
(8) Total Participation Purchases	170	170	170	170	170	170
(9) Total Participation Sales	3	5	5	8	8	-
(10) Adjusted Net Capability (7+8-9)	420	888	887	1351	1350	1359
(11) Net Reserve Capacity Obligation (6x15%)**	126	138	141	154	158	170
(12) Total Firm Capacity Obligation (5+11)	869	1052	979	1181	1101	1303
(13) Surplus or (Deficit) Capacity (10-12)	(449)	(164)	(92)	170	249	56

All Numbers Are in Megawatts

* Summer, May 1 - October 31; Winter, November 1 - April 30

**For a Predominantly Hydro System (6x10%)

EXHIBIT 29

	Year	1981		1982		1983	
	Season*	S	W	S	W	S	W
(1)	Seasonal System Demand	1130	1366	1234	1494	1364	1635
(2)	Annual System Demand	1250	1366	1366	1494	1494	1635
(3)	Total Firm Purchases	91	117	91	117	91	117
(4)	Total Firm Sales	-	-	-	-	-	-
(5)	Seasonal Adjusted Net Demand (1-3+4)	1039	1249	1143	1377	1273	1518
(6)	Annual Adjusted Net Demand (2-3+4)	1159	1249	1275	1377	1403	1518
(7)	Net Generating Capability	1188	1189	1188	1189	1188	1189
(8)	Total Participation Purchases	170	170	170	170	170	170
(9)	Total Participation Sales	-	-	-	-	-	-
(10)	Adjusted Net Capability (7+8-9)	1358	1359	1358	1359	1358	1359
(11)	Net Reserve Capacity Obligation (6x15%)**	173	187	191	207	211	228
(12)	Total Firm Capacity Obligation (5+11)	1212	1436	1334	1584	1484	1746
(13)	Surplus or (Deficit) Capacity (10-12)	146	(77)	24	(225)	(126)	(387)

All Numbers Are in Megawatts
* Summer, May 1 - October 31; Winter, November 1 - April 30
**For a Predominantly Hydro System (6x10%)

EXHIBIT 29

	Year	1984		1985		1986	
	Season*	S	W	S	W	S	W
(1)	Seasonal System Demand	1494	1790	1637	1962	1793	2152
(2)	Annual System Demand	1635	1790	1790	1962	1962	2152
(3)	Total Firm Purchases	91	117	91	117	91	117
(4)	Total Firm Sales	-	-	-	-	-	-
(5)	Seasonal Adjusted Net Demand (1-3+4)	1403	1673	1546	1845	1702	2035
(6)	Annual Adjusted Net Demand (2-3+4)	1544	1673	1699	1845	1871	2035
(7)	Net Generating Capability	1188	1189	1188	1189	1188	1189
(8)	Total Participation Purchases	170	170	170	170	170	170
(9)	Total Participation Sales	-	-	-	-	-	-
(10)	Adjusted Net Capability (7+8-9)	1358	1359	1358	1359	1358	1359
(11)	Net Reserve Capacity Obligation (6x15%)**	231	251	255	277	281	306
(12)	Total Firm Capacity Obligation (5+11)	1634	1924	1801	2122	1983	2341
(13)	Surplus or (Deficit) Capacity (10-12)	(276)	(565)	(443)	(763)	(625)	(982)

All Numbers Are in Megawatts
* Summer, May 1 - October 31; Winter, November 1 - April 30
**For a Predominantly Hydro System (6x10%)

EXHIBIT 29

	Year	1987		1988		1989	
	Season*	S	W	S	W	S	W
(1)	Seasonal System Demand	1969	2361	2159	2593	2370	2847
(2)	Annual System Demand	2152	2361	2361	2593	2593	2847
(3)	Total Firm Purchases	91	117	91	117	91	117
(4)	Total Firm Sales	-	-	-	-	-	-
(5)	Seasonal Adjusted Net Demand (1-3+4)	1878	2244	2068	2476	2279	2730
(6)	Annual Adjusted Net Demand (2-3+4)	2061	2244	2270	2476	2502	2730
(7)	Net Generating Capability	1188	1189	1188	1189	1188	1189
(8)	Total Participation Purchases	170	170	170	170	170	170
(9)	Total Participation Sales	-	-	-	-	-	-
(10)	Adjusted Net Capability (7+9-9)	1358	1359	1358	1359	1358	1359
(11)	Net Reserve Capacity Obligation (6x15%)**	309	337	341	371	375	410
(12)	Total Firm Capacity Obligation (5+11)	2187	2581	2409	2847	2654	3140
(13)	Surplus or (Deficit) Capacity (10-12)	(829)	(1222)	(1051)	(1488)	(1296)	(1781)

All Numbers Are in Megawatts
* Summer, May 1 - October 31; Winter, November 1 - April 30
**For a Predominantly Hydro System (6x10%)

EXHIBIT 29

	Year	1990	
	Season*	S	W
(1)	Seasonal System Demand	2606	3131
(2)	Annual System Demand	2847	3131
(3)	Total Firm Purchases	91	117
(4)	Total Firm Sales	-	-
(5)	Seasonal Adjusted Net Demand (1-3+4)	2515	3014
(6)	Annual Adjusted Net Demand (2-3+4)	2756	3014
(7)	Net Generating Capability	1188	1189
(8)	Total Participation Purchases	170	170
(9)	Total Participation Sales	-	-
(10)	Adjusted Net Capability (7+8-9)	1358	1359
(11)	Net Reserve Capacity Obligation (6x15%)**	413	452
(12)	Total Firm Capacity Obligation (5+11)	2928	3466
(13)	Surplus or (Deficit) Capacity (10-12)	(1570)	(2107)

All Numbers Are in Megawatts

* Summer, May 1 - October 31; Winter, November 1 - April 30

**For a Predominantly Hydro System (6x10%)

EXHIBIT 30
CPA LOAD CAPACITY AND RESERVE AS PROJECTED WITH ALL PROPOSED FACILITIES
EA636 (f)

		sum 1975	win 1975	sum 1976	win 1976	sum 1977	win 1977	sum 1978	win 1978
(1)	Seasonal System Demand	332	428	364	470	400	517	439	561
(2)	Annual System Demand	391	428	428	470	470	517	517	561
(3)	Total Seasonal Firm Purchases	157	291	164	325	106	111	86	111
(4)	Total Seasonal Firm Sales	0	0	0	0	0	0	0	0
(5)	Seasonal Adjusted Net Demand (1 - 3 + 4)	175	137	200	145	294	406	353	450
(6)	Annual Adjusted Net Demand (2 - 3 + 4)	234	137	264	145	364	406	431	450
(7)	Net Generating Capacity	11	16	16	16	16	16	76	331
(8)	Total Seasonal Participation Purchases	202	171	170	170	170	170	170	170
(9)	Total Seasonal Participation Sales	0	0	0	0	0	0	0	0
(10)	Adjusted Net Capability (7 + 8 - 9)	213	187	186	186	186	186	246	501
(11)	Net Reserve Capacity Obligation (6 x 15%)	35	21	40	22	55	61	65	68
(12)	Total Firm Capacity Obligation (5 + 11)	210	158	240	167	349	467	418	518
(13)	Surplus (+) or Deficit (-) Capacity (10 - 12)	3	29	-54	19	-163	-281	-172	-17

EXHIBIT 30
CPA LOAD CAPACITY AND RESERVE AS PROJECTED WITH ALL PROPOSED FACILITIES
EA636 (f)

		sum 1979	win 1979	sum 1980	win 1980	sum 1981	win 1981	sum 1982	win 1982
(1)	Seasonal System Demand	477	609	518	662	563	720	612	784
(2)	Annual System Demand	561	609	609	662	662	720	720	784
(3)	Total Seasonal Firm Purchases	86	111	86	111	86	111	86	111
(4)	Total Seasonal Firm Sales	0	0	0	0	0	0	0	0
(5)	Seasonal Adjusted Net Demand (1 - 3 + 4)	391	498	432	551	477	609	526	673
(6)	Annual Adjusted Net Demand (2 - 3 + 4)	475	498	523	551	576	609	634	673
(7)	Net Generating Capacity	330	582	581	582	581	582	581	582
(8)	Total Seasonal Participation Purchases	170	170	170	170	170	170	170	170
(9)	Total Seasonal Participation Sales	0	0	0	0	0	0	0	0
(10)	Adjusted Net Capability (7 + 8 - 9)	500	752	751	752	751	752	751	752
(11)	Net Reserve Capacity Obligation (6 x 15%)	71	75	79	83	86	91	95	101
(12)	Total Firm Capacity Obligation (5 + 11)	462	573	511	634	563	700	621	774
(13)	Surplus (+) or Deficit (-) Capacity (10 - 12)	+38	+179	+240	+118	+188	+52	+130	-22

EXHIBIT 30

CPA LOAD CAPACITY AND RESERVE AS PROJECTED WITH ALL PROPOSED FACILITIES

EA636 (f)

		sum 1983	win 1983	sum 1984	win 1984	sum 1985	win 1985	sum 1986	win 1986
(1)	Seasonal System Demand	666	855	727	933	793	1018	865	1114
(2)	Annual System Demand	784	855	855	933	933	1018	1018	1114
(3)	Total Seasonal Firm Purchases	86	111	86	111	86	111	86	111
(4)	Total Seasonal Firm Sales	0	0	0	0	0	0	0	0
(5)	Seasonal Adjusted Net Demand (1 - 3 + 4)	580	744	641	822	707	907	779	1003
(6)	Annual Adjusted Net Demand (2 - 3 + 4)	698	744	769	822	847	907	932	1003
(7)	Net Generating Capacity	581	642	641	642	841	842	841	842
(8)	Total Seasonal Participation Purchases	170	170	170	170	170	170	170	170
(9)	Total Seasonal Participation Sales	0	0	0	0	0	0	0	0
(10)	Adjusted Net Capability (7 + 8 - 9)	751	812	811	812	1011	1012	1011	1012
(11)	Net Reserve Capacity Obligation (6 x 15%)	105	112	115	123	127	136	140	151
(12)	Total Firm Capacity Obligation (5 + 11)	685	856	756	945	834	1043	919	1154
(13)	Surplus (+) or Deficit (-) Capacity (10 - 12)	+66	-44	+55	-133	+177	-31	+92	-142

EXHIBIT 30

CPA LOAD CAPACITY AND RESERVE AS PROJECTED WITH ALL PROPOSED FACILITIES

EA636 (f)

		sum 1987	win 1987	sum 1988	win 1988	sum 1989	win 1989	sum 1990	win 1990
(1)	Seasonal System Demand	947	1217	1034	1333	1133	1461	1242	1601
(2)	Annual System Demand	1114	1217	1217	1333	1333	1461	1461	1601
(3)	Total Seasonal Firm Purchases	86	111	86	111	86	111	86	111
(4)	Total Seasonal Firm Sales	0	0	0	0	0	0	0	0
(5)	Seasonal Adjusted Net Demand (1 - 3 + 4)	861	1106	948	1222	1047	1350	1156	1490
(6)	Annual Adjusted Net Demand (2 - 3 + 4)	1028	1106	1131	1222	1247	1350	1375	1490
(7)	Net Generating Capacity	841	842	841	842	841	842	841	842
(8)	Total Seasonal Participation Purchases	170	170	170	170	170	170	170	170
(9)	Total Seasonal Participation Sales	0	0	0	0	0	0	0	0
(10)	Adjusted Net Capability (7 + 8 - 9)	1011	1012	1011	1012	1011	1012	1011	1012
(11)	Net Reserve Capacity Obligation (6 x 15%)	154	166	170	183	187	203	206	224
(12)	Total Firm Capacity Obligation (5 + 11)	1015	1272	1118	1405	1234	1553	1362	1714
(13)	Surplus (+) or Deficit (-) Capacity (10 - 12)	-4	-260	-107	-393	-223	-541	-351	-702

EXHIBIT 31

UPA - LOAD, CAPACITY AND RESERVE AS PROJECTED
WITH ALL PROPOSED FACILITIES (MW)
EA 636 (f)

	Year	1975		1976		1977	
	Season*	S	W	S	W	S	W
(1)	Seasonal System Demand	302	345	328	378	360	414
(2)	Annual System Demand	321	345	345	378	378	414
(3)	Total Firm Purchases	13	26	5	6	5	6
(4)	Total Firm Sales	-	-	-	-	-	-
(5)	Seasonal Adjusted Net Demand (1-3+4)	289	319	323	372	355	408
(6)	Annual Adjusted Net Demand (2-3+4)	308	319	340	372	373	408
(7)	Net Generating Capability	237	237	237	237	237	237
(8)	Total Participation Purchases	107	138	27	55	40	50
(9)	Total Participation Sales	2	2	2	3	3	3
(10)	Adjusted Net Capability (7+8-9)	342	373	262	289	274	284
(11)	Net Reserve Capacity Obligation (6x15%) **	46	48	51	56	56	61
(12)	Total Firm Capacity Obligation (5+11)	335	367	374	428	411	469
(13)	Surplus or (Deficit) Capacity (10-12)	(7)	(6)	(112)	(139)	(137)	(185)

All Numbers Are in Megawatts

* Summer, May 1 - October 31; Winter, November 1 - April 30

** For a Predominantly Hydro System (6x10%)

EXHIBIT 31

	Year	1978		1979		1980	
	Season*	S	W	S	W	S	W
(1)	Seasonal System Demand	395	470	452	535	516	588
(2)	Annual System Demand	414	470	470	535	535	588
(3)	Total Firm Purchases	5	6	5	6	5	6
(4)	Total Firm Sales	-	-	-	-	-	-
(5)	Seasonal Adjusted Net Demand (1-3+4)	390	464	447	529	511	582
(6)	Annual Adjusted Net Demand (2-3+4)	409	464	465	529	530	582
(7)	Net Generating Capability	237	452	452	667	667	667
(8)	Total Participation Purchases	-	-	-	-	-	-
(9)	Total Participation Sales	3	5	5	8	8	-
(10)	Adjusted Net Capability (7+8-9)	234	447	447	659	659	667
(11)	Net Reserve Capacity Obligation (6x15%)**	61	70	70	79	79	87
(12)	Total Firm Capacity Obligation (5+11)	451	534	517	608	590	669
(13)	Surplus or (Deficit) Capacity (10-12)	(217)	(87)	(70)	51	69	(2)

All Numbers Are in Megawatts

* Summer, May 1 - October 31; Winter, November 1 - April 30

** For a Predominantly Hydro System (6x10%)

EXHIBIT 31

	Year	1981		1982		1983	
	Season*	S	W	S	W	S	W
(1)	Seasonal System Demand	567	646	622	710	698	780
(2)	Annual System Demand	588	646	646	710	710	780
(3)	Total Firm Purchases	5	6	5	6	5	6
(4)	Total Firm Sales	-	-	-	-	-	-
(5)	Seasonal Adjusted Net Demand (1-3+4)	562	640	617	704	693	774
(6)	Annual Adjusted Net Demand (2-3+4)	583	640	641	704	705	774
(7)	Net Generating Capability	667	667	667	667	667	667
(8)	Total Participation Purchases	-	-	-	-	-	-
(9)	Total Participation Sales	-	-	-	-	-	-
(10)	Adjusted Net Capability (7+8-9)	667	667	667	667	667	667
(11)	Net Reserve Capacity Obligation (6x15%)**	87	96	96	106	106	116
(12)	Total Firm Capacity Obligation (5+11)	649	736	713	810	799	890
(13)	Surplus or (Deficit) Capacity (10-12)	18	(69)	(46)	(143)	(132)	(223)

All Numbers Are in Megawatts

* Summer, May 1 - October 31; Winter, November 1 - April 30

** For a Predominantly Hydro System (6x10%)

EXHIBIT 31

Year	1984		1985		1986	
Season*	S	W	S	W	S	W
(1) Seasonal System Demand	767	857	844	944	928	1038
(2) Annual System Demand	780	857	857	944	944	1038
(3) Total Firm Purchases	5	6	5	6	5	6
(4) Total Firm Sales	-	-	-	-	-	-
(5) Seasonal Adjusted Net Demand (1-3+4)	762	851	839	938	923	1032
(6) Annual Adjusted Net Demand (2-3+4)	775	851	852	938	939	1032
(7) Net Generating Capability	667	667	667	667	667	667
(8) Total Participation Purchases	-	-	-	-	-	-
(9) Total Participation Sales	-	-	-	-	-	-
(10) Adjusted Net Capability (7+8-9)	667	667	667	667	667	667
(11) Net Reserve Capacity Obligation (6x15%)**	116	128	128	141	141	155
(12) Total Firm Capacity Obligation (5+11)	878	979	967	1079	1064	1187
(13) Surplus or (Deficit) Capacity (10-12)	(211)	(312)	(300)	(412)	(397)	(520)

All Numbers Are in Megawatts

* Summer, May 1 - October 31; Winter, November 1 - April 30

** For a Predominantly Hydro System (6x10%)

EXHIBIT 31

	Year	1987		1988		1989	
	Season*	S	W	S	W	S	W
(1)	Seasonal System Demand	1022	1144	1125	1260	1237	1386
(2)	Annual System Demand	1038	1144	1144	1260	1260	1386
(3)	Total Firm Purchases	5	6	5	6	5	6
(4)	Total Firm Sales	-	-	-	-	-	-
(5)	Seasonal Adjusted Net Demand (1-3+4)	1017	1138	1120	1254	1232	1380
(6)	Annual Adjusted Net Demand (2-3+4)	1033	1138	1139	1254	1255	1380
(7)	Net Generating Capability	667	667	667	667	667	667
(8)	Total Participation Purchases	-	-	-	-	-	-
(9)	Total Participation Sales	-	-	-	-	-	-
(10)	Adjusted Net Capability (7+8-9)	667	667	667	667	667	667
(11)	Net Reserve Capacity Obligation (6x15%)**	155	171	171	188	188	207
(12)	Total Firm Capacity Obligation (5+11)	1172	1309	1291	1442	1420	1587
(13)	Surplus or (Deficit) Capacity (10-12)	(505)	(642)	(624)	(775)	(753)	(920)

All Numbers Are in Megawatts

* Summer, May 1 - October 31; Winter, November 1 - April 30

** For a Predominantly Hydro System (6x10%)

EXHIBIT 31

	Year	1990	
	Season*	S	W
(1)	Seasonal System Demand	1364	1530
(2)	Annual System Demand	1386	1530
(3)	Total Firm Purchases	5	6
(4)	Total Firm Sales	-	-
(5)	Seasonal Adjusted Net Demand (1-3+4)	1359	1524
(6)	Annual Adjusted Net Demand (2-3+4)	1381	1524
(7)	Net Generating Capability	667	667
(8)	Total Participation Purchases	-	-
(9)	Total Participation Sales	-	-
(10)	Adjusted Net Capability (7+8-9)	667	667
(11)	Net Reserve Capacity Obligation (6x15%)**	207	228
(12)	Total Firm Capacity Obligation (5+11)	1566	1752
(13)	Surplus or (Deficit) Capacity (10-12)	(899)	(1085)

All Numbers Are in Megawatts

* Summer, May 1 - October 31; Winter, November 1 - April 30

** For a Predominantly Hydro System (6x10%)

EXHIBIT 32

COMBINED LOAD CAPACITY AND RESERVE AS PROJECTED
WITH ALL PROPOSED FACILITIES (MW)
EA 636 (f)

Year	1975		1976		1977	
Season*	S	W	S	W	S	W
(1) Seasonal System Demand	634	773	692	848	760	931
(2) Annual System Demand	712	773	773	848	848	931
(3) Total Firm Purchases	170	317	169	331	111	117
(4) Total Firm Sales	-	-	-	-	-	-
(5) Seasonal Adjusted Net Demand (1-3+4)	464	456	523	517	649	814
(6) Annual Adjusted Net Demand (2-3+4)	542	456	604	517	737	814
(7) Net Generating Capability	248	253	253	253	253	253
(8) Total Participation Purchases	309	309	197	225	210	220
(9) Total Participation Sales	2	2	2	3	3	3
(10) Adjusted Net Capability (7+8-9)	555	560	448	475	460	470
(11) Net Reserve Capacity Obligation (6x15%)**	81	69	91	78	111	122
(12) Total Firm Capacity Obligation (5+11)	545	525	614	595	760	936
(13) Surplus or (Deficit) Capacity (10-12)	10	35	(166)	(120)	(300)	(466)

All Numbers Are in Megawatts
* Summer, May 1 - October 31; Winter, November 1 - April 30
**For a Predominantly Hydro System (6x10%)

EXHIBIT 32

	Year	1978		1979		1980	
	Season*	S	W	S	W	S	W
(1)	Seasonal System Demand	834	1031	929	1144	1034	1250
(2)	Annual System Demand	931	1031	1031	1144	1144	1250
(3)	Total Firm Purchases	91	117	91	117	91	117
(4)	Total Firm Sales	-	-	-	-	-	-
(5)	Seasonal Adjusted Net Demand (1-3+4)	743	914	838	1027	943	1133
(6)	Annual Adjusted Net Demand (2-3+4)	840	914	940	1027	1053	1133
(7)	Net Generating Capability	313	783	782	1249	1248	1249
(8)	Total Participation Purchases	170	170	170	170	170	170
(9)	Total Participation Sales	3	5	5	8	8	-
(10)	Adjusted Net Capability (7+8-9)	480	948	947	1411	1410	1419
(11)	Net Reserve Capacity Obligation (6x15%)**	126	138	141	154	158	170
(12)	Total Firm Capacity Obligation (5+11)	869	1052	979	1181	1101	1303
(13)	Surplus or (Deficit) Capacity (10-12)	(389)	(104)	(32)	230	309	116

All Numbers Are in Megawatts
* Summer, May 1 - October 31; Winter, November 1 - April 30
**For a Predominantly Hydro System (6x10%)

EXHIBIT 32

	Year	1981		1982		1983	
	Season*	S	W	S	W	S	W
(1)	Seasonal System Demand	1130	1366	1234	1494	1364	1635
(2)	Annual System Demand	1250	1366	1366	1494	1494	1635
(3)	Total Firm Purchases	91	117	91	117	91	117
(4)	Total Firm Sales	-	-	-	-	-	-
(5)	Seasonal Adjusted Net Demand (1-3+4)	1039	1249	1143	1377	1273	1518
(6)	Annual Adjusted Net Demand (2-3+4)	1159	1249	1275	1377	1403	1518
(7)	Net Generating Capability	1248	1249	1248	1249	1248	1309
(8)	Total Participation Purchases	170	170	170	170	170	170
(9)	Total Participation Sales	-	-	-	-	-	-
(10)	Adjusted Net Capability (7+8-9)	1418	1419	1418	1419	1418	1479
(11)	Net Reserve Capacity Obligation (6x15%)**	173	187	191	207	211	228
(12)	Total Firm Capacity Obligation (5+11)	1212	1436	1334	1584	1484	1746
(13)	Surplus or (Deficit) Capacity (10-12)	206	(17)	84	(165)	(66)	(267)

All Numbers Are in Megawatts
* Summer, May 1 - October 31; Winter, November 1 - April 30
**For a Predominantly Hydro System (6x10%)

EXHIBIT 32

Year		1984		1985		1986	
Season*		S	W	S	W	S	W
(1)	Seasonal System Demand	1494	1790	1637	1962	1793	2152
(2)	Annual System Demand	1635	1790	1790	1962	1962	2152
(3)	Total Firm Purchases	91	117	91	117	91	117
(4)	Total Firm Sales	-	-	-	-	-	-
(5)	Seasonal Adjusted Net Demand (1-3+4)	1403	1673	1546	1845	1702	2035
(6)	Annual Adjusted Net Demand (2-3+4)	1544	1673	1699	1845	1871	2035
(7)	Net Generating Capability	1308	1309	1508	1509	1508	1509
(8)	Total Participation Purchases	170	170	170	170	170	170
(9)	Total Participation Sales	-	-	-	-	-	-
(10)	Adjusted Net Capability (7+8-9)	1478	1479	1678	1679	1678	1679
(11)	Net Reserve Capacity Obligation (6x15%)**	231	251	255	277	281	306
(12)	Total Firm Capacity Obligation (5+11)	1634	1924	1801	2122	1983	2341
(13)	Surplus or (Deficit) Capacity (10-12)	(156)	(445)	(123)	(443)	(305)	(662)

All Numbers Are in Megawatts

* Summer, May 1 - October 31; Winter, November 1 - April 30

**For a Predominantly Hydro System (6x10%)

EXHIBIT 32

Year	1987		1988		1989	
Season*	S	W	S	W	S	W
(1) Seasonal System	1969	2361	2159	2593	2370	2847
(2) Annual System Demand	2152	2361	2361	2593	2593	2847
(3) Total Firm Purchases	91	117	91	117	91	117
(4) Total Firm Sales	-	-	-	-	-	-
(5) Seasonal Adjusted Net Demand (1-3+4)	1878	2244	2068	2476	2279	2730
(6) Annual Adjusted Net Demand (2-3+4)	2061	2244	2270	2476	2502	2730
(7) Net Generating Capability	1508	1509	1508	1509	1508	1509
(8) Total Participation Purchases	170	170	170	170	170	170
(9) Total Participation Sales	-	-	-	-	-	-
(10) Adjusted Net Capability (7+8-9)	1678	1679	1678	1679	1678	1679
(11) Net Reserve Capacity Obligation (6x15%)**	309	337	341	371	375	410
(12) Total Firm Capacity Obligation (5+11)	2187	2581	2409	2847	2654	3140
(13) Surplus or (Deficit) Capacity (10-12)	(509)	(902)	(731)	(1168)	(976)	(1461)

All Numbers Are in Megawatts
* Summer, May 1 - October 31; Winter, November 1 - April 30
**For a Predominantly Hydro System (6x10%)

EXHIBIT 32

	Year	1990	
	Season*	S	W
(1)	Seasonal System Demand	2606	3131
(2)	Annual System Demand	2847	3131
(3)	Total Firm Purchases	91	117
(4)	Total Firm Sales	-	-
(5)	Seasonal Adjusted Net Demand (1-3+4)	2515	3014
(6)	Annual Adjusted Net Demand (2-3+4)	2756	3014
(7)	Net Generating Capability	1508	1509
(8)	Total Participation Purchases	170	170
(9)	Total Participation Sales	-	-
(10)	Adjusted Net Capability (7+8-9)	1678	1679
(11)	Net Reserve Capacity Obligation (6x15%)**	413	452
(12)	Total Firm Capacity Obligation (5+11)	2928	3466
(13)	Surplus or (Deficit) Capacity (10-12)	(1250)	(1787)

All Numbers Are in Megawatts
* Summer, May 1 - October 31; Winter, November 1 - April 30
**For a Predominantly Hydro System (6x10%)

EXHIBIT 33
CPA PROPOSED CAPACITY ADDITIONS AND PROPOSED CAPACITY REQUIREMENTS
EA636 (g)

Year	Proposed Capacity Addition
1978 summer	Peaking capacity 60 MW
1983 winter	Peaking capacity 60 MW
1985 summer	Base Load capacity 200 MW

Proposed Capacity Retirements

None

EXHIBIT 34
CPA LOAD CAPACITY PROFILE FOR 1974 (MW)
EA636 (h)

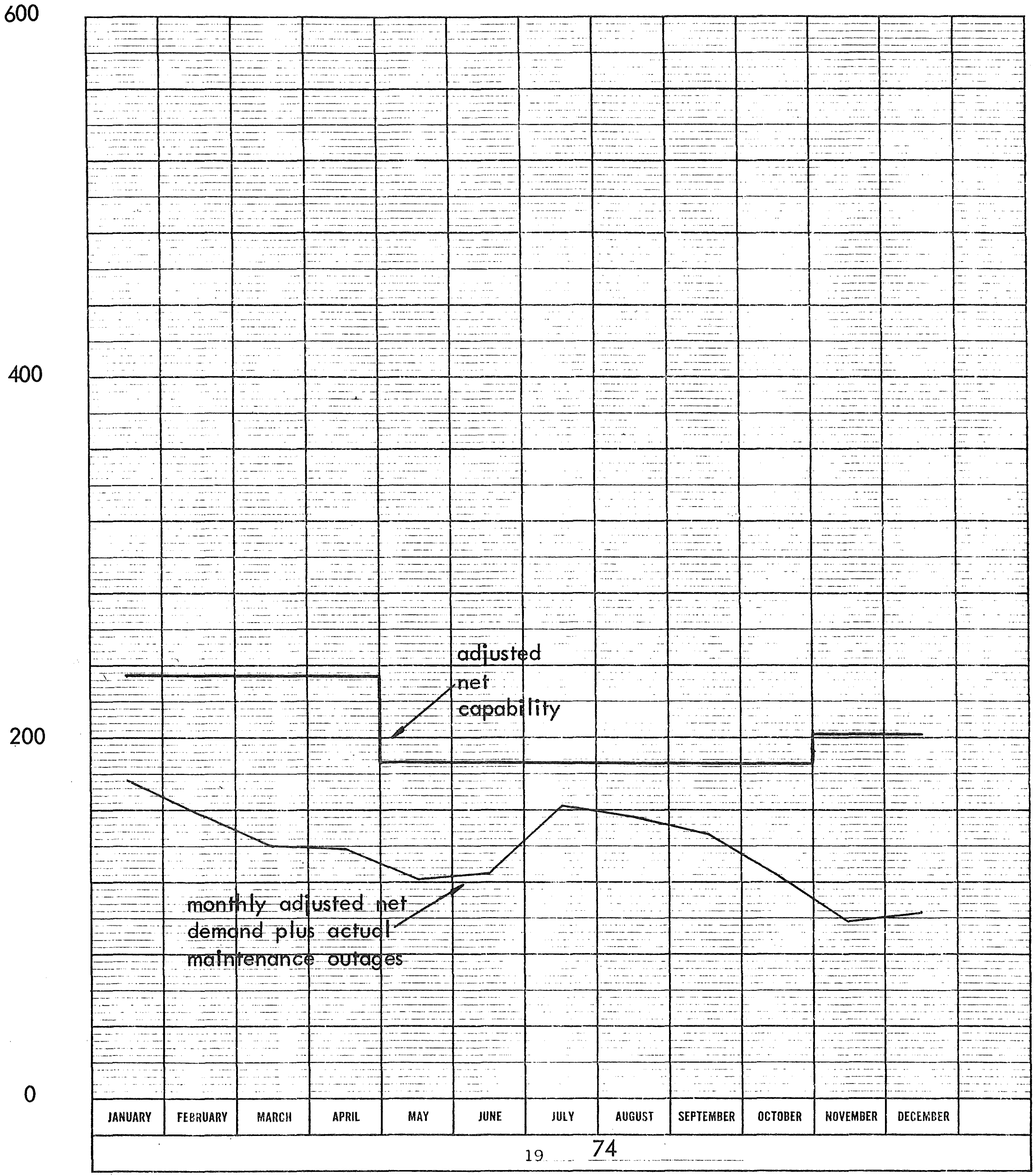


EXHIBIT 34
CPA LOAD CAPACITY PROFILE FOR 1975 (MW)
EA636 (h)

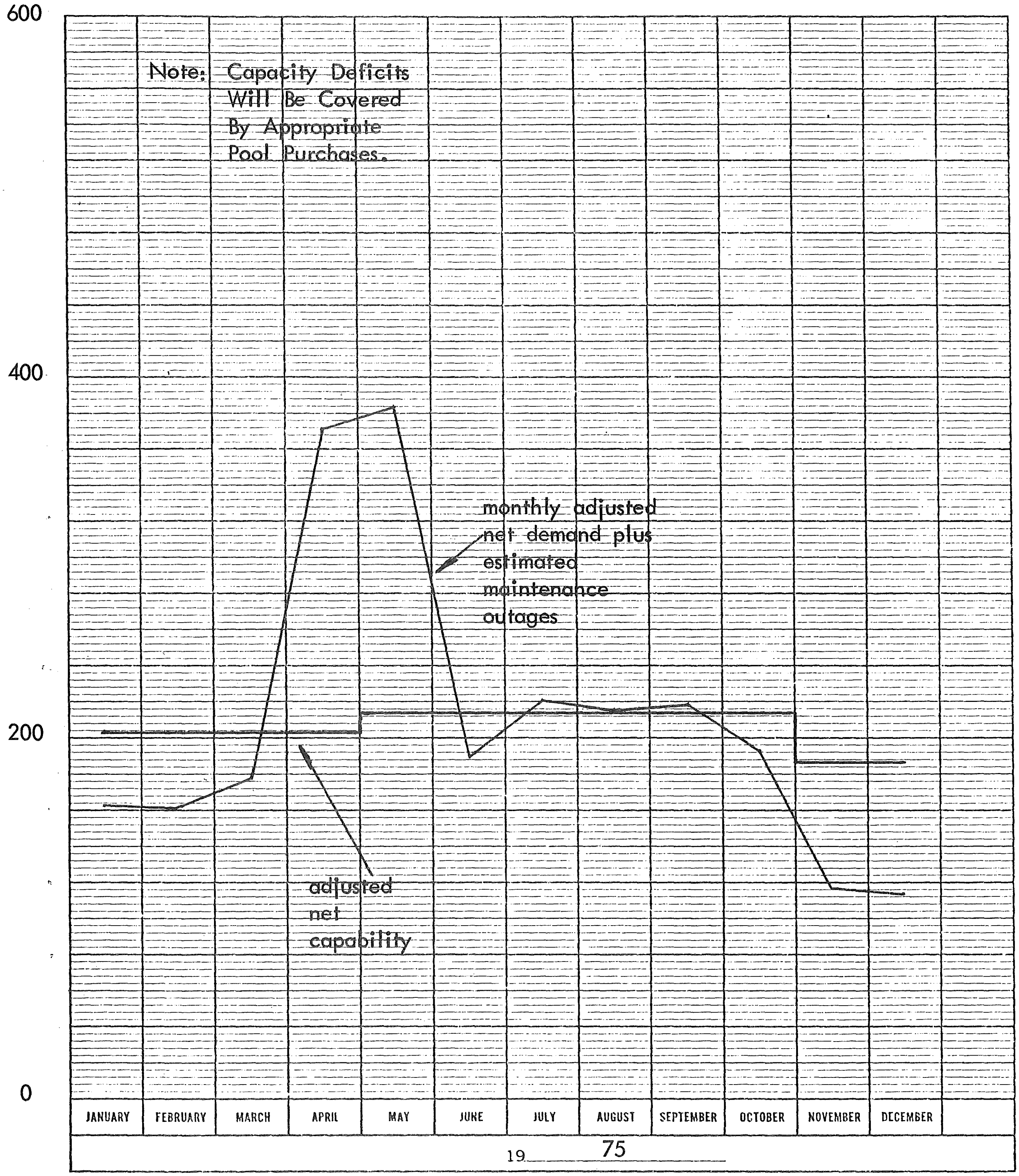


EXHIBIT 34
CPA LOAD CAPACITY PROFILE FOR 1977 (MW)
EA636 (h)

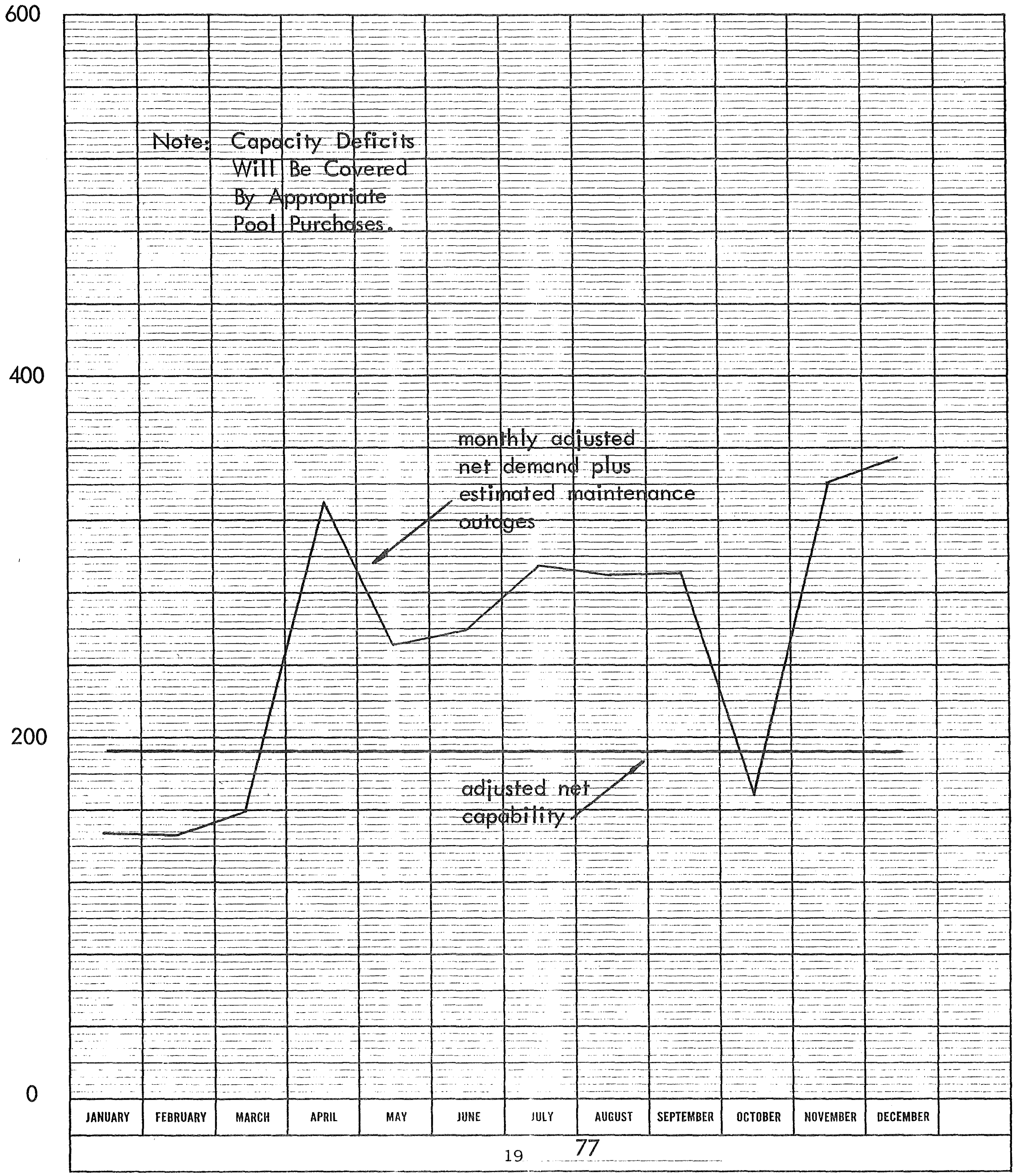


EXHIBIT 34
CPA LOAD CAPACITY PROFILE FOR 1979 (MW)
EA636 (h)

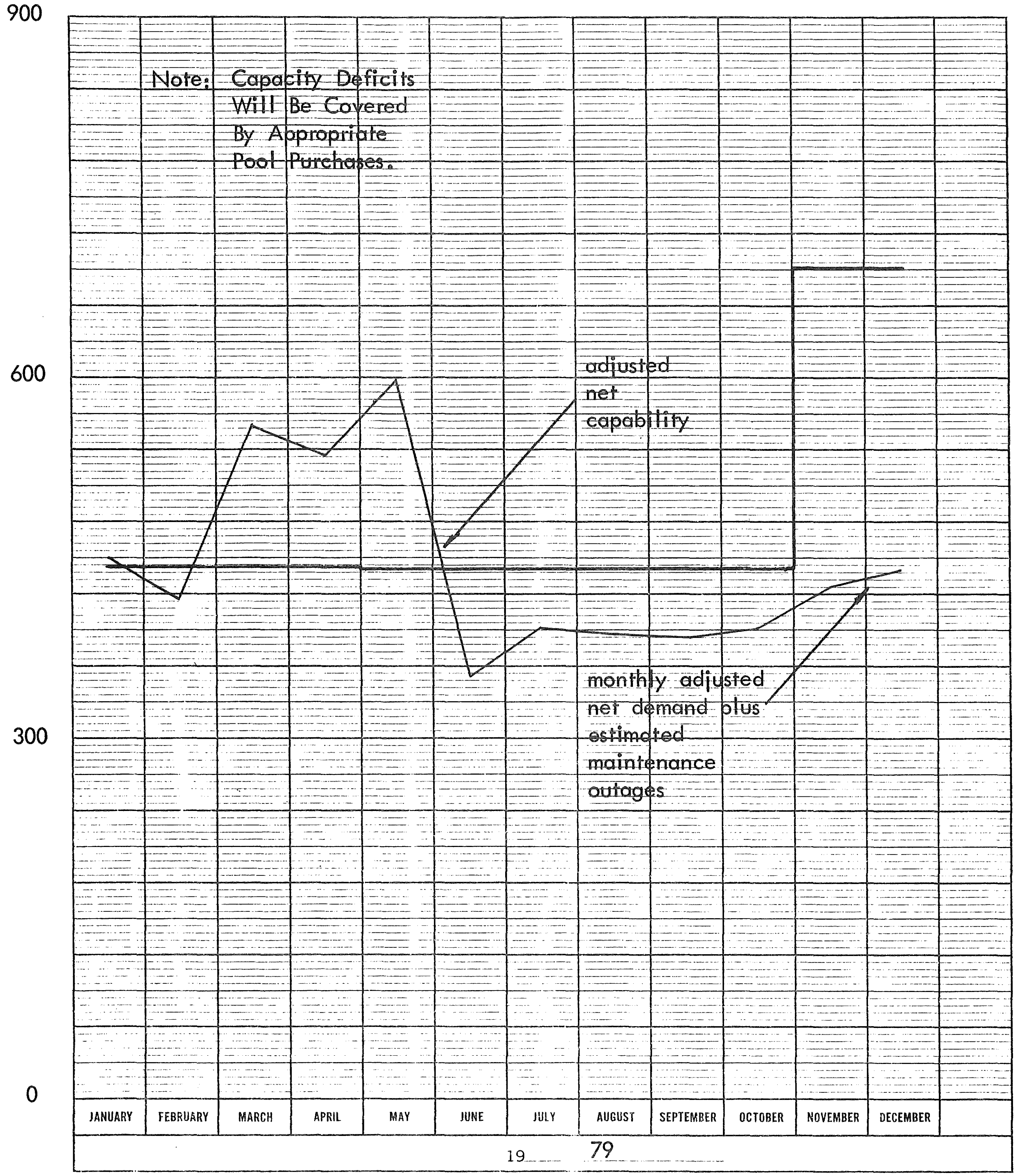


EXHIBIT 35
UPA - LOAD CAPACITY PROFILE
EA 636 (h)

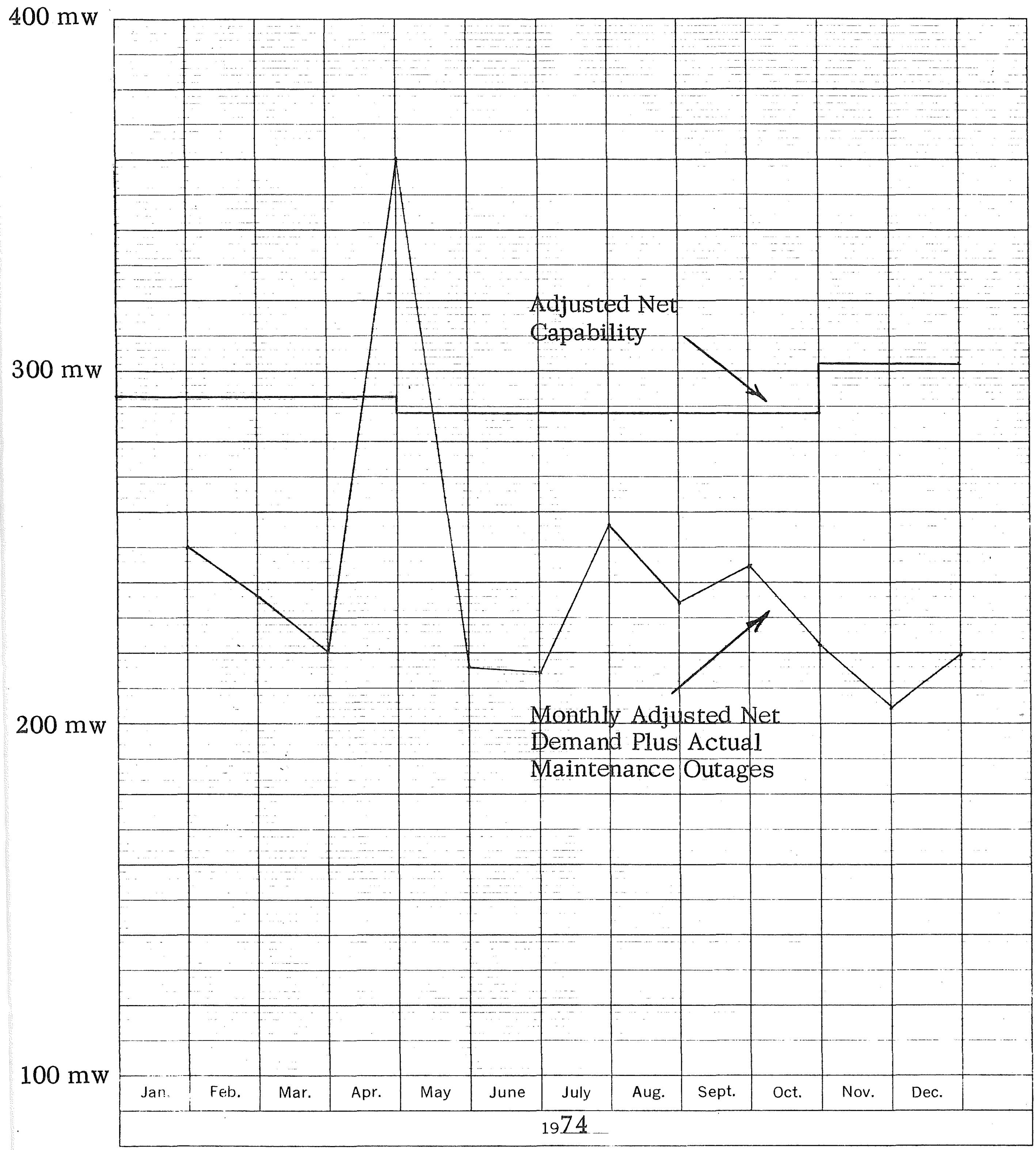


EXHIBIT 35

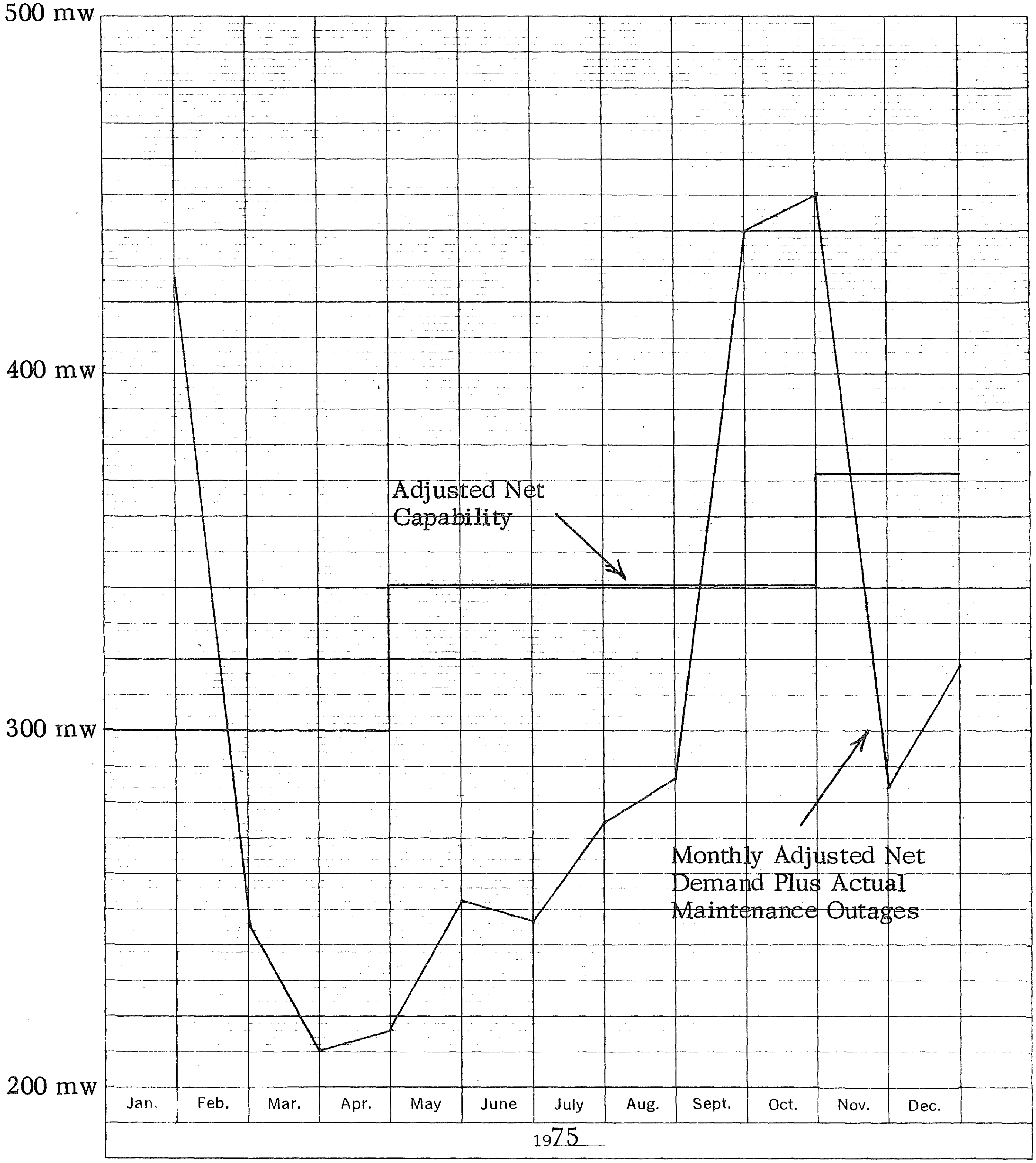

500 mw
400 mw
300 mw
200 mw
Adjusted Net Capability
Monthly Adjusted Net Demand Plus Actual Maintenance Outages
Jan.
Feb.
Mar.
Apr.
May
June
July
Aug.
Sept.
Oct.
Nov.
Dec.
1975

EXHIBIT 35

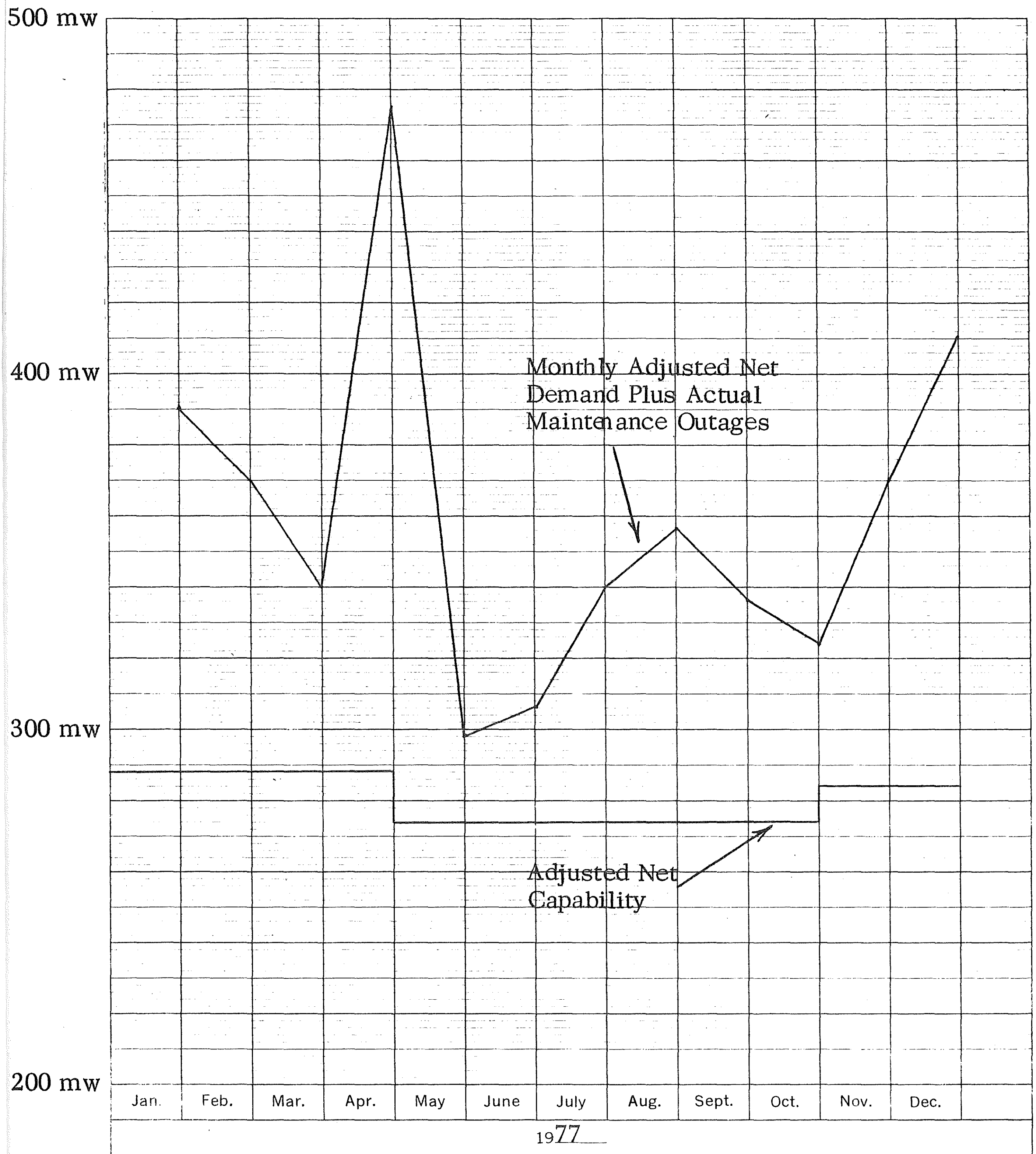

500 mw
400 mw
300 mw
200 mw
Monthly Adjusted Net Demand Plus Actual Maintenance Outages
Adjusted Net Capability
Jan.
Feb.
Mar.
Apr.
May
June
July
Aug.
Sept.
Oct.
Nov.
Dec.
1977

EXHIBIT 35

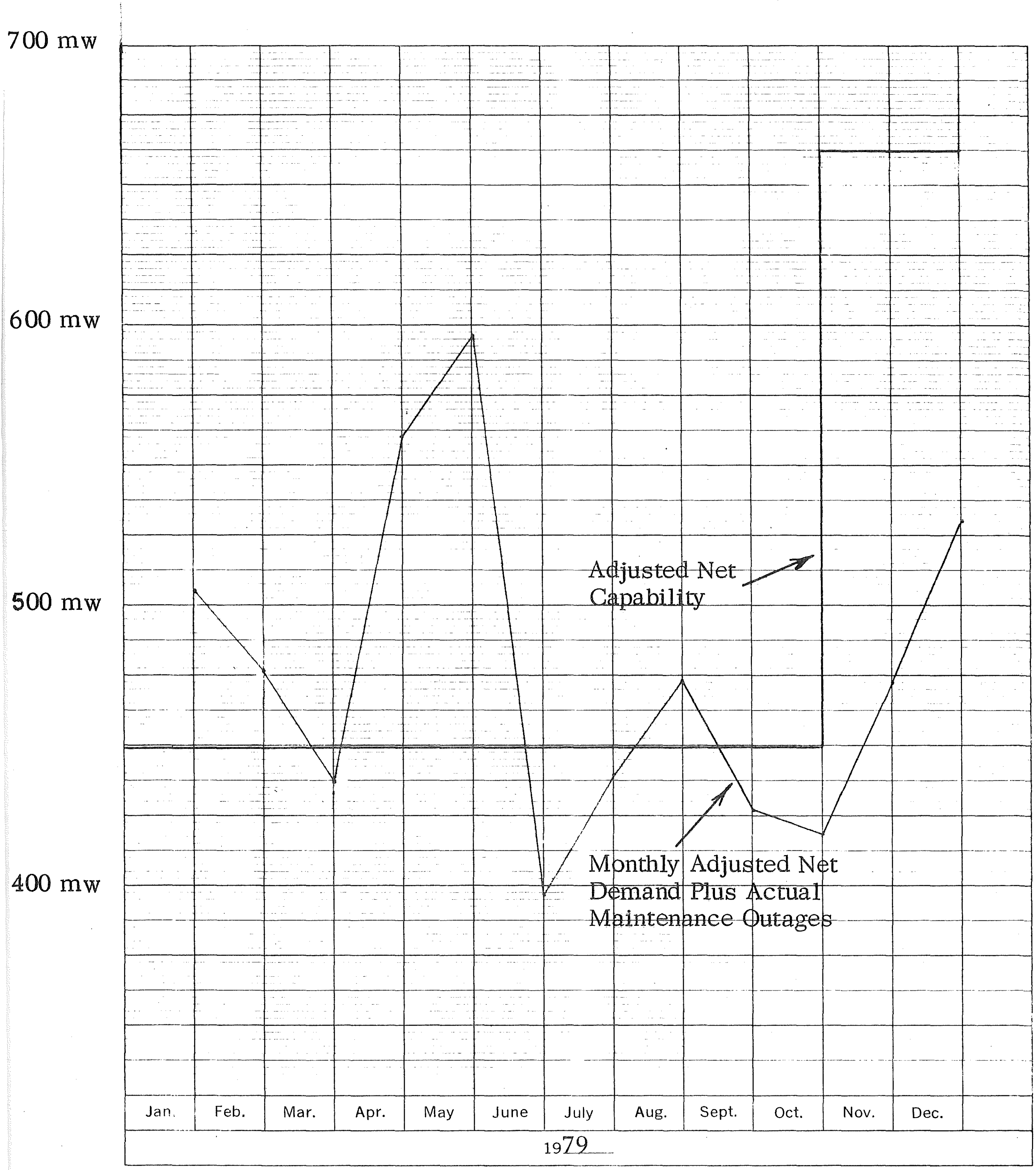

700 mw
600 mw
500 mw
400 mw
Adjusted Net Capability
Monthly Adjusted Net Demand Plus Actual Maintenance Outages
Jan.
Feb.
Mar.
Apr.
May
June
July
Aug.
Sept.
Oct.
Nov.
Dec.
1979

EXHIBIT 36
COMBINED LOAD CAPACITY PROFILE
EA 636 (h)

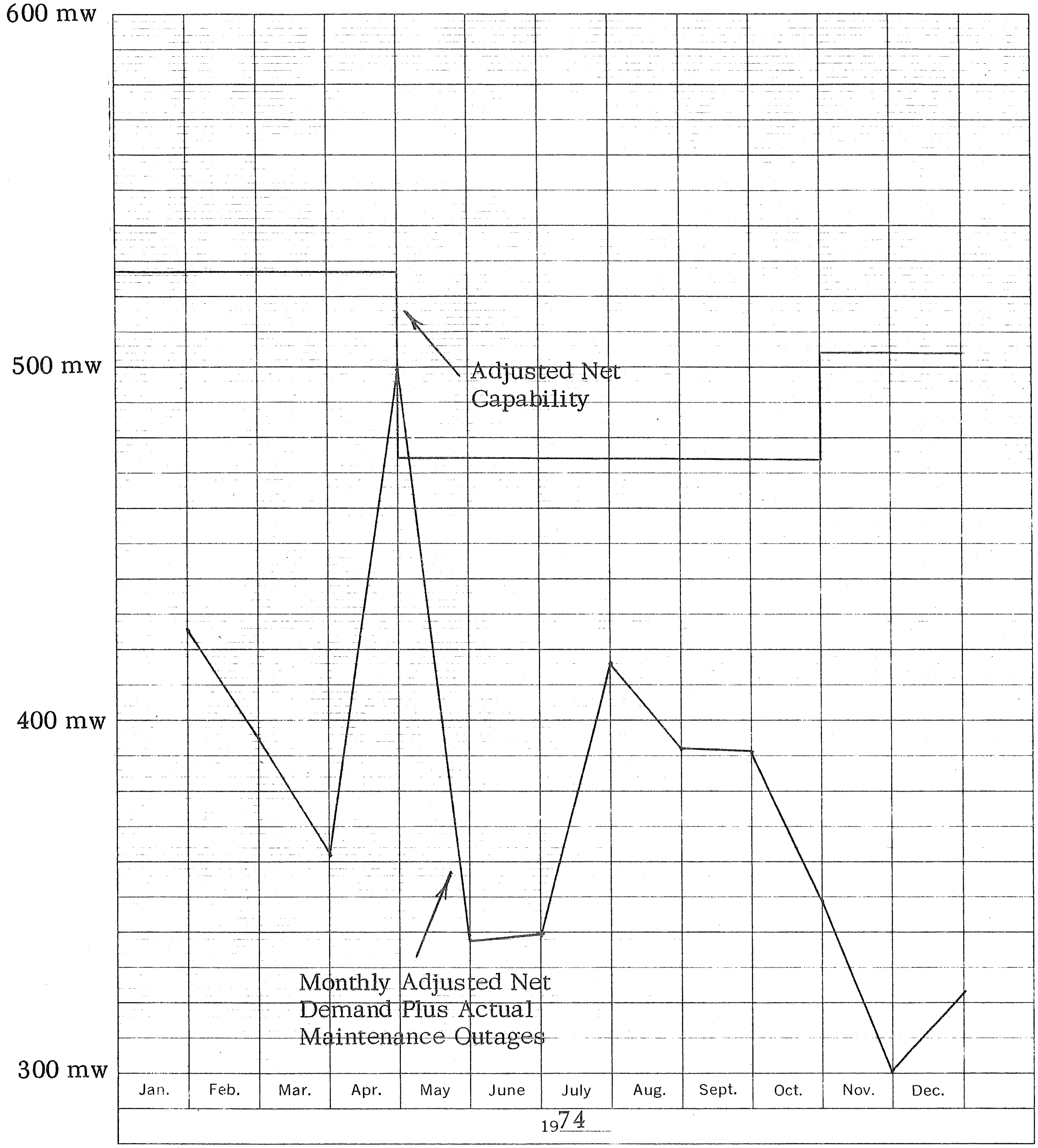


EXHIBIT 36

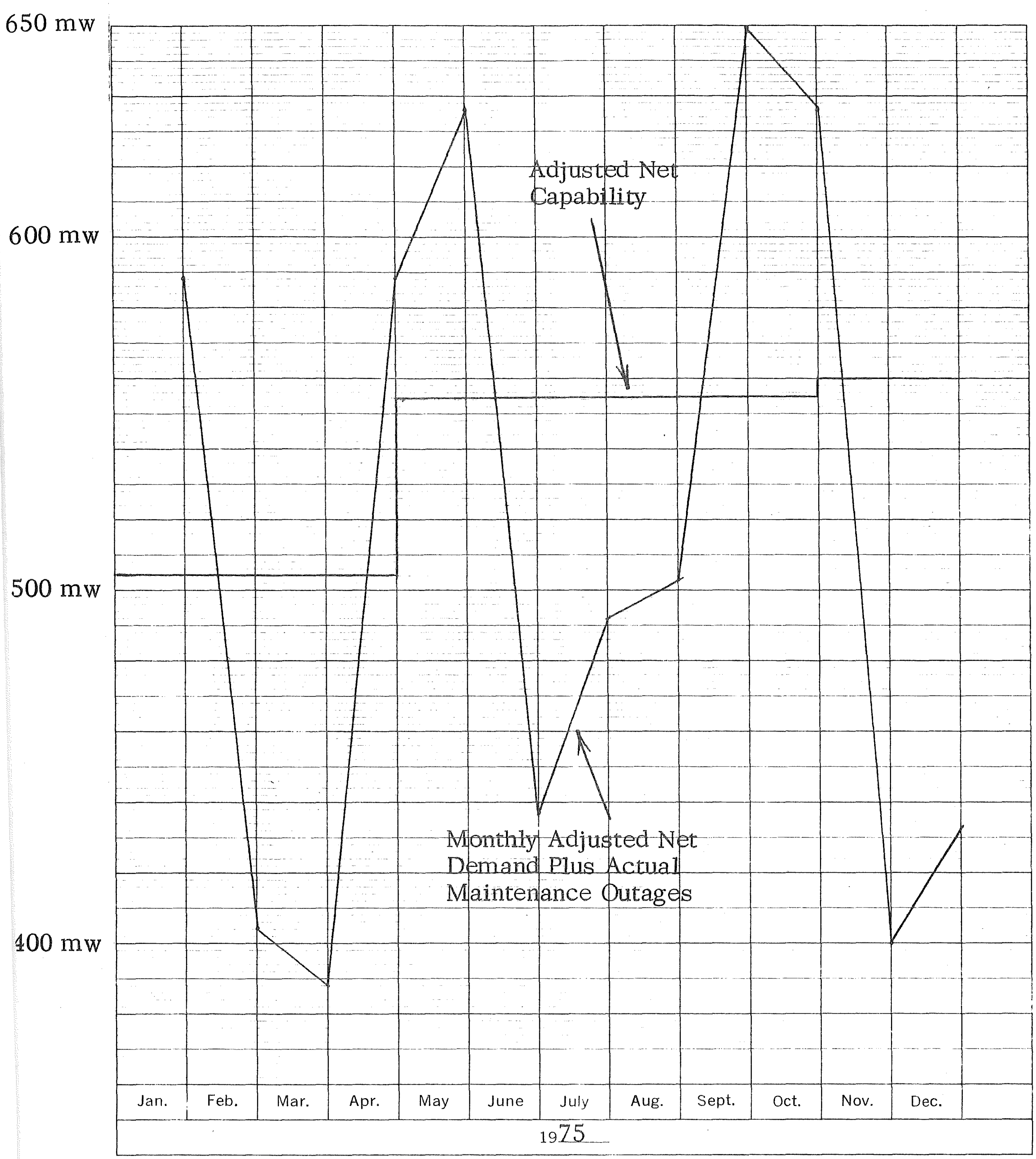

650 mw
600 mw
500 mw
400 mw
Adjusted Net Capability
Monthly Adjusted Net Demand Plus Actual Maintenance Outages
Jan.
Feb.
Mar.
Apr.
May
June
July
Aug.
Sept.
Oct.
Nov.
Dec.
1975

EXHIBIT 36

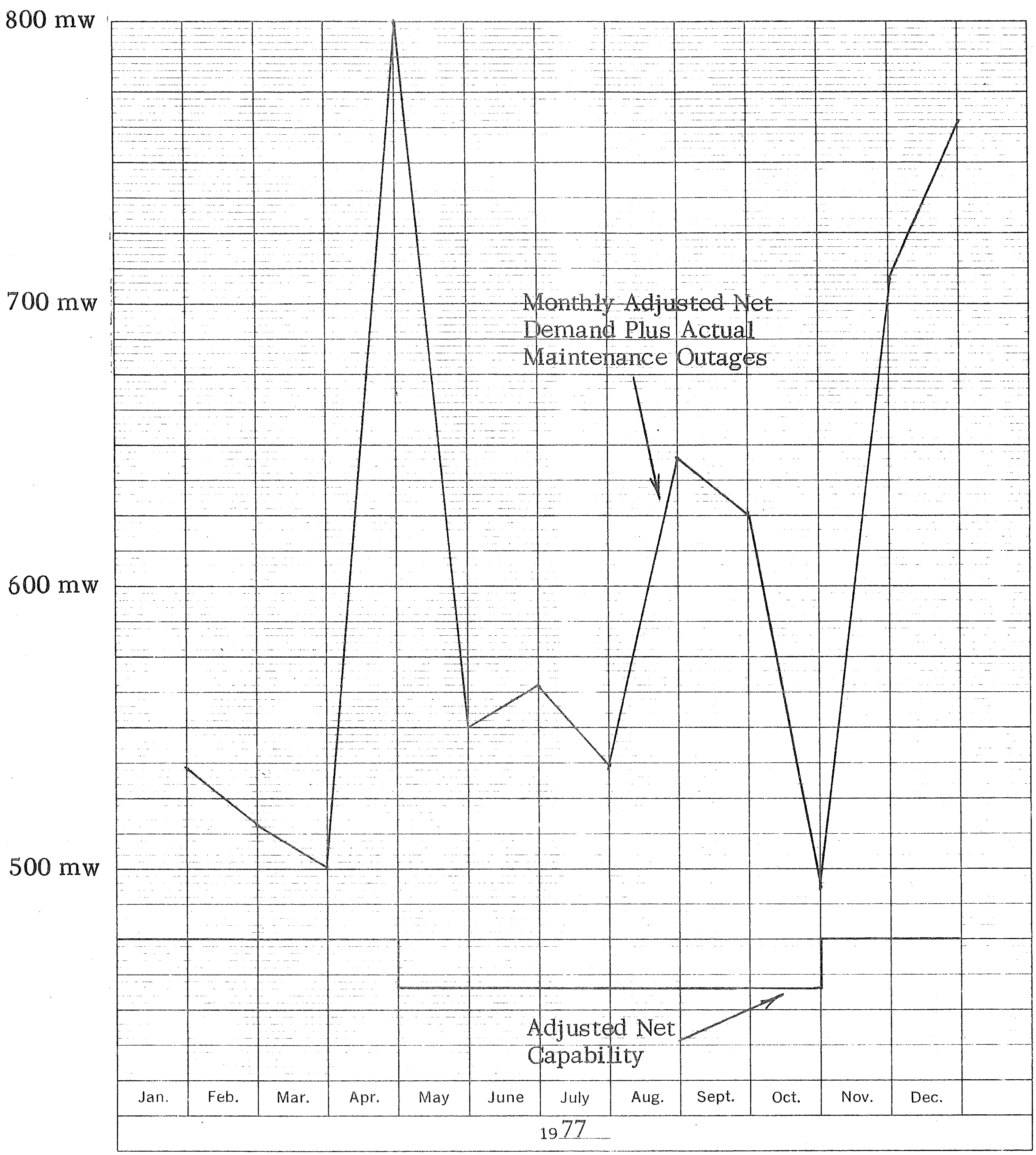
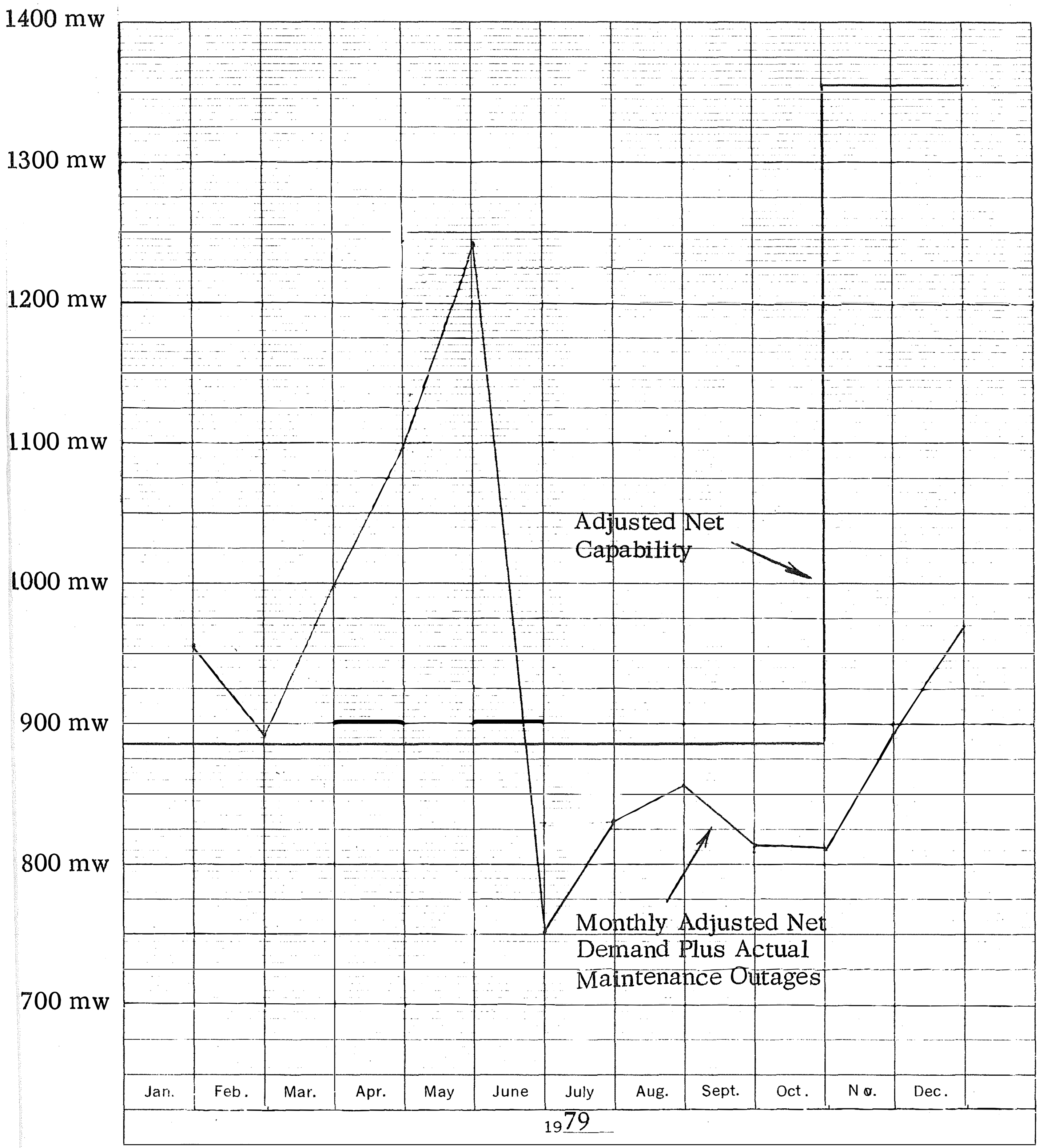

800 mw
700 mw
600 mw
500 mw
Monthly Adjusted Net Demand Plus Actual Maintenance Outages
Adjusted Net Capability
Jan.
Feb.
Mar.
Apr.
May
June
July
Aug.
Sept.
Oct.
Nov.
Dec.
1977

EXHIBIT 36


1400 mw
1300 mw
1200 mw
1100 mw
1000 mw
900 mw
800 mw
700 mw
Adjusted Net Capability
Monthly Adjusted Net Demand Plus Actual Maintenance Outages
Jan.
Feb.
Mar.
Apr.
May
June
July
Aug.
Sept.
Oct.
Nov.
Dec.
1979