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New York Power Authority

Capacity and Energy Production Achievable at the Niagara Power Project

and

Niagara Load Study

March 2007

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March 10, 2007

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Executive Summary

The determination of the capacity and energy available from a hydroelectric project depends on the project's physical capabilities, regulations under which it operates, river flows available and the nature of the loads being served. Since the New York Power Authority's (NYPA) Niagara Power Project entered service in 1961, additional hydrologic data has become available, customers and their requirements have changed, and the units at the Robert Moses Niagara Power Plant (RMNPP), the project's primary generating plant, have been upgraded and overhauled. This report has therefore been prepared to re-examine the ability of the project to meet the capacity and energy requirements of the current customers, and determine the increases in marketable output that are possible as a result of the upgrade.

The purpose of the RMNPP upgrade includes increases in unit nameplate capacity, as well as overhaul and replacement of principal generating equipment. The nameplate capacity increase allows increased production to take place during periods of peak electrical demand. The nameplate capacity increase itself did not increase the firm capacity of the Project, nor the energy that can be produced.

However, the upgrade of the RMNPP units increased the efficiency of the units. This increase in efficiency allows for the production of additional firm capacity, peaking capacity and energy with the same flows available from the Niagara River. The efficiency of the units has been increased from about 92.7% to about 94.4%, an increase of approximately 1.7%. While performance tests have not been performed on all of the RMNPP units, sufficient tests have been conducted that rating tables for the sharing of the Niagara River flows in accordance with the 1950 Treaty between the United States and Canada have been submitted to the International Joint Commission for approval. This increase in efficiency represents an increase in the firm capacity of the Project of 32 MW, and an increase in the peaking capacity of 9 MW.

Energy will be available to meet these capacity values with the same probability of curtailment as existed for the original units with the lower established capacity values. Analyses of the customer loads that are served confirms that approximately 15% of the time on average the loads cannot be met based on energy available, and curtailment is necessary, though in some months the load cannot be met about 25% of the time. This curtailment rate is based primarily on flows available from the river.

Capacity and Energy Production Achievable at the Niagara Power Project

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1. Introduction

In 1990 the Power Authority began an upgrade of the aging Robert Moses Niagara Power Plant (RMNPP) at the Niagara Power Project (NPP). The purpose of this upgrade was to increase the installed capacity and efficiency of the turbine-generator units, and to provide for a major overhaul of the principal generating systems. The upgrade of the 13th and last of the units was completed in December of 2006.

When this program was conceived in the 1980s, one of its objectives was an increase in the installed capacity of the units to allow optimal use of the combined RMNPP and the Lewiston Pump-Generating Plant (LPGP), so that daytime peaking production could be increased and higher-cost fossil fuel generation could be offset. This installed capacity, sometimes referred to as nameplate or machine capacity, must be distinguished from the firm and peaking capacity available from the overall project, as explained further in this report.

The determination of the capacity and energy available from any hydroelectric project depends on the Project's physical capabilities, regulations under which it operates and river flows available, and it also depends on the nature of the loads being served. Since the NPP entered service in 1961, additional hydrologic data has become available, customers and their requirements have changed, and the units have been upgraded and overhauled. This report has therefore been prepared to re-examine the ability of the Project to meet the capacity and energy requirements of the current customers, and determine the increases that are possible as a result of the upgrade.

Before providing a description of the capacity and energy achievable, a summary of the methodology is provided, followed by a brief summary of the physical design of the two plants making up the NPP, regulatory requirements and a description of how the project operates.

2. Study Methodology

To re-examine the capacity and energy which the Project can provide, updated river flow data were organized, and the efficiency data resulting from field tests on the old and upgraded

RMNPP units were organized. Customer load profiles were developed by the Power Authority's Marketing, Economic Development and Supply Planning Business Unit. Since customer demand varies by month, the load profiles were developed for each month. This represents the first time that comprehensive customer load profile data was available for an analysis of the Project's ability to meet loads. The load profiles represent the power required for each hour of the day, which therefore represents the energy requirement.

In order to follow a load profile and provide energy to a customer, it is a prerequisite that the plant be able to provide sufficient capacity. Installed, or nameplate, capacity, refers to the power output possible from the generation equipment itself, provided sufficient flows are available. Firm and peaking capacity refer to the output of a project under low river flow conditions. The distinction between firm and peaking capacity is the number of hours that the power can be provided to the customer.

Therefore, the analyses began by determining the maximum capacity which the Project can achieve under a given river flow. The maximum achievable capacity for each month and flow value was compared to the customer loads to first determine if the peak loads can be achieved. Since the contracted capacity values (firm and peak) were historically established under very low flows in the river, it would be expected that the Project can generally meet the customer peak loads on the load profiles.

The next step in the analyses was a determination of whether the load profile could then be met throughout the remainder of the day, for each month and the range of flow values for that month.

Energy represents power acting for a period of time, and is typically expressed in megawatt-hours (MWhrs). For each month, the energy required to meet the customer load profiles was directly calculated from the load profiles. Similarly, the energy which can be produced by the project was calculated from the flows available from the river, considering the additional energy available on weekdays using LPGP (and the additional deficit on weekends when the Lewiston Reservoir must be re-filled). A comparison was then made to determine how often the project could meet the energy requirements as defined by the load profiles.

The upgraded units provide both improved efficiency and higher nameplate capacity. The analyses show that the higher nameplate does not contribute to meeting customer loads – the old units can generally achieve the customer loads. The analyses also show the effect of the higher efficiency on capacity and energy production.

3. Physical Features of the Project

The Niagara Power Project includes two separate hydroelectric power plants – the RMNPP and the LPGP. The two plants are connected by a forebay approximately 4,300 feet long. Water is diverted from the upper Niagara River by two underground conduits into the forebay, from which it is drawn to either plant. LPGP connects the forebay to Lewiston Reservoir.

The RMNPP is located at the western end of the forebay, and is a large but conventional hydroelectric plant with 13 turbine-generator units. The RMNPP draws water from the forebay, and discharges water into the lower Niagara River. The original units were rated 167 MVA, 150 MW, 0.9 power factor. These units have been upgraded and overhauled, and now have a rating of 215 MVA, 193.5 MW, 0.9 power factor. As practical operating limits, the RMNPP units have historically been operated to about 175 MW, based on the capability of the generator cooling systems and since voltage support was rarely needed. The upgraded units can be operated to approximately 200 MW, limited by cavitation in the new turbines. This cavitation limit for the upgraded units is higher than that of the old units. The average net head when generating is approximately 300 feet.

The Lewiston Pump-Generating Plant is located at the eastern end of the forebay. LPGP was built to pump water from the forebay into the Lewiston Reservoir during periods of low electric demand, and generate using this stored water during periods of high electric demand. LPGP houses 12 reversible pump-turbine units, each rated 37,000 HP as a motor and 20 MW as a generator at 75 feet net head. The aggregate installed capacity of LPGP is therefore 240 MW under 75-foot head conditions. Under high head conditions, with a full reservoir and low forebay (which occurs when Niagara River flows are high), LPGP can achieve an output of about 330 MW. However, such high-output operation is rare, since under high river flow conditions, additional flows and output from LPGP are not essential as the RMNPP units are loaded directly from river flows.

Since LPGP is designed to store and release flows from Lewiston Reservoir, its flow capability is important – each unit can pump at a rate of approximately 3,000 cubic feet per second (cfs) to 4,500 cfs as a pump, depending on the elevations of Lewiston Reservoir and the forebay. Each unit can discharge approximately 3,000 to 4,900 cfs when generating, again depending on the elevations of the reservoir and forebay, and on the desired output. Pumping and generating heads vary from about 60 feet to about 120 feet due to fluctuations in both the reservoir and forebay. This is an unusually large range for a pumped storage project and machine performance varies over this range.

Lewiston Reservoir is a man-made reservoir with a usable storage capacity of 69,500 acre-feet. It is formed by a rock dike with a length of about 6.5 miles. The water surface elevations vary between a high of 656.5 feet and a low of 619 ft feet 1955 IGLD. When the reservoir is completely drawn down after generating, the average remaining water depth is only about 3 feet.

Figure 1 illustrates the principal physical features of the Niagara Power Project.

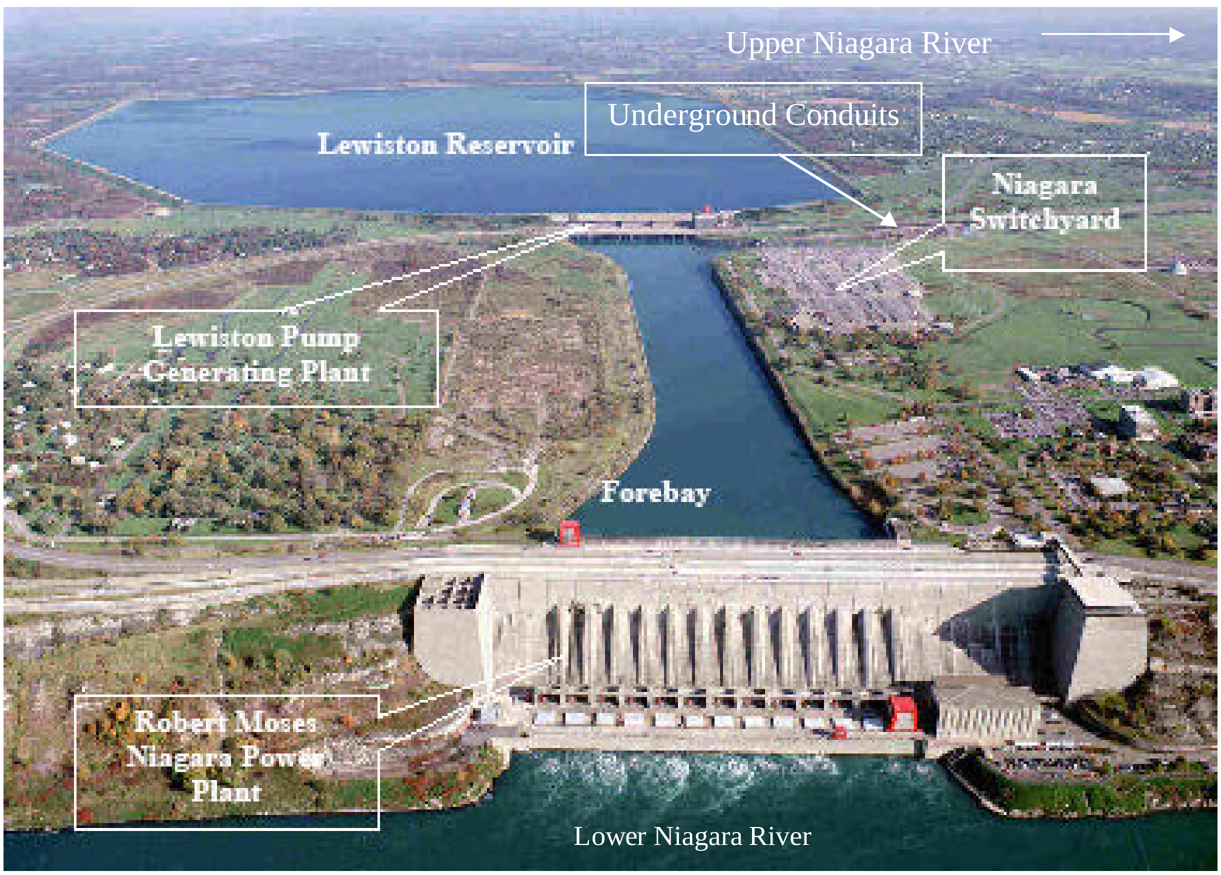


Figure 1 – Niagara Power Project

4. Regulatory Environment

The design and operation of the Niagara Power Project is governed by several federal and state requirements, and by an international treaty.

The Power Authority was licensed to build and operate the Niagara Power Project by the Federal Power Commission, (now known as the Federal Energy Regulatory Commission (FERC), with an original license that expires on August 31, 2007. The Power Authority has filed an application for a new license.

The Niagara Redevelopment Act, passed by Congress in 1957, required that a license for the Niagara Power Project be issued to the New York Power Authority, and stipulated that the Power Authority was authorized to utilize the U.S. share of the water of the Niagara River. The Niagara Redevelopment Act also required that preference for 50% of the firm capacity of the project be given to public bodies and non-profit cooperatives in economic transmission distance, with 20% of this preference power going to neighboring states. The Act also required that low-cost power be made available to industry in Western New York.

While FERC monitors dam safety and other aspects of compliance with the license, the project is obligated under the 1950 Niagara River Water Diversion Treaty (Treaty) between the United States and Canada to share the waters of the Niagara River. The International Joint Commission (IJC) assures that the waters were shared equally, and the Power Authority must demonstrate adherence to the IJC's requirements.

In addition to requiring a sharing of the waters, the Treaty provides that at least 100,000 cfs be discharged over Niagara Falls from 8:00 am to 10:00 pm during the period April 1 to September 15, and from 8:00 am to 8:00 pm during the period September 16 to October 31 each year. This period is referred to as the Tourist Season. At all other times, at least 50,000 cfs must be discharged over Niagara Falls. The Treaty provides that all flows not discharged over the Falls may be diverted for power purposes. The IJC also ensures that the Treaty flows over Niagara Falls are met.

5. Project Operation

The interaction of the two plants enhances the project's ability to provide firm capacity, peaking capacity and energy, and an understanding of how the plants interact is necessary to understand the overall production capability of the Project.

The Treaty's requirement that greater flows be discharged over the Falls during daytime periods in the tourist season, plus the higher value and demand for energy during daytime periods in both tourist and non-tourist seasons, sets the stage for how the operation of RMNPP and LPGP needs to be coordinated. Since electrical demand is lowest at night, some of the available flows are stored by pumping with the LPGP units into Lewiston Reservoir.

The conduits which draw water from the upper Niagara River have no control structures. While intake gates were included in the design to allow flow in the conduits to be stopped, they do not regulate the flow. The flow through the conduits is actually determined by the difference in water elevations between the upper Niagara River and the forebay. The elevation of the forebay is in turn established by the flow through the RMNPP and LPGP units.

During the tourist season the flows that may be taken from the river are greater at night, so the forebay needs to be dropped to a lower elevation at night to provide the necessary gradient to convey those flows. This forces the LPGP units to pump against higher heads than they will be generating with the next day. This is relevant to the determination of net energy production from the overall project.

Not all of the available flows are pumped into Lewiston Reservoir at night. The RMNPP units still generate with some of the flows at night, providing the pumping power to LPGP, and meeting night-time customer loads.

During the daytime periods, the LPGP units generate with the water stored in Lewiston Reservoir. The flows from LPGP plus those drawn from the river through the conduits to the forebay are then used to generate at RMNPP. Therefore, production is considerably higher during daytime periods than at night, which allows meeting of customer loads, which are likewise generally higher during the day.

The project operates optimally on a weekly cycle, with the reservoir progressively drawn down more each weekday than it is re-filled at night. On Monday morning, the reservoir is typically full, and by Friday night the reservoir is typically at its lowest level. The reservoir is refilled by additional pumping over weekend periods, when energy value is at its lowest, so that by Monday morning the reservoir is again full and ready to repeat the cycle. Total energy that can be produced over the course of a week is not increased by the use of LPGP. In fact, use of the LPGP decreases net energy production because the pumping and generating efficiency cycle is less than 100% as a consequence of energy losses in the pump-turbine units. However, the LPGP produces value through the re-timing of off-peak energy to help meeting daily and weekly peak power needs. Note that the reservoir is not sufficiently large to store flows for seasonal release.

In a manner similar to that which Lewiston Reservoir is used to store water at night for release during the day, the Grass Island Pool is also used to store water at night for use during the day. The Grass Island Pool is a portion of the upper Niagara River. The elevation of the river may be varied slightly, storing water. The amount that can be stored is small compared to Lewiston Reservoir. Nevertheless, when conditions permit it can provide additional generation capability during daytime periods.

The requirements that a stable ice cover be formed on Lake Erie, and the need to sometimes discharge additional flows over Niagara Falls to flush ice and prevent ice jams and flooding, periodically reduces the flows available for generation in the winter months. This is factored into the production analyses later in this report.

6. General Concepts in Capacity and Energy Determination

The unit ratings described above only indicate the maximum capability of the individual units at RMNPP and LPGP. Firm, or dependable, capacity refers to the power that a hydroelectric project can provide during periods of low flow in the river. Firm capacity also depends on whether the project can store water for use during low river flow periods and the load shape being served. As noted above, Lewiston Reservoir cannot be used to store water seasonally to overcome long-term periods of low flow, but only to re-time production within a week.

Peaking capacity refers to the output of a project for short periods of time, generally for a few hours during daytime periods when electric demand is highest.

The combined capabilities of the RMNPP and LPGP units have been used to establish the firm and peaking capacities of the Niagara Power Project. As described above, the Project can store water in Lewiston Reservoir by pumping a portion of the available flows into it at night by LPGP. Daytime generation can then be increased above that using only the daytime entitlement flows by discharging stored flows through LPGP and then through the RMNPP. However, night-time production decreases in this process. Similarly, some flows can be stored in the Grass Island Pool at night for use during daytime periods, but if it is used this again decreases nighttime production.

The establishment of the current 1,880 MW firm capacity of the Niagara Power Project was a result of Federal Power Commission litigation (*State of Vermont Public Service Board v. Power Authority of the State of New York* 55 FPC 1109 (1976), *Initial Decision* 55 FPC 1121 at 1144-45 (1975) (Docket E-8746). The 1,880 MW was predicated on low river flows and on meeting certain load shapes, using a load factor approach. The load factor is the ratio of the average daily power required by a customer divided by the maximum daily power required. Use of this load factor approach recognizes that customers will require more power during daytime periods than at night. However, it represents an approximate method to characterize loads, as many entirely different load shapes can have the same load factor, and different load shapes represent different energy requirements. The 1,880 MW value was determined to be available only during daytime periods, and lesser amounts, based on load factor assumptions, were determined to be available at night.

In the analyses that supported the earlier determination of project power, the energy that could be produced by the Project was determined to be available to support the 24-hour customer load factors only about 75% of the time (3 out of 4 years). The 1,880 MW value itself could be achieved for short periods each day, often more than 75% of the time, but at the cost of lower production during other hours each day.

In the 1970s the peaking capacity of the Niagara Power Project was determined to be 2,400 MW. This power level would only be achievable for a few hours each day. It was predicated on 95% exceedance flows (flows that would be equaled or exceeded 95% of the time, described later in this report), so that, provided the units were operable, it represented a power level that could be achieved each weekday for a few hours 95% of the time.

Firm and peaking capacity at the Niagara Power Project are established assuming that all 12 units at LPGP and 13 units at RMNPP would be available for generation. At some hydroelectric projects not all units may need to operate simultaneously to achieve the established firm capacity. This is not true for the Niagara Power Project – all 12 LPGP units are needed to achieve the firm and peaking capacities, though under the low flows used to establish these capacities failure of one RMNPP unit would not have a large impact on Project capacity.

7. Flows in the Niagara River

The Niagara Power Project shares use of the waters of the Niagara River with Niagara Falls and Ontario Power Generation. The Niagara River drains four of the five Great Lakes, which with their connecting rivers and tributaries represent a drainage area of approximately 263,700 square miles.

At the present time, the flow in the Niagara River is determined by summing the flows through the turbines in the Robert Moses Niagara Power Plant, the Sir Adam Beck Plant operated by Ontario Power Generation, the flows over the Falls and flows in the Welland Canal Diversion. The flows are reported to the IJC's International Niagara River Board of Control. Flows have been determined in this manner since the Project went into operation in 1961.

Flows have also been measured for periods before the Niagara Power Project was constructed. The IJC has prepared basis of comparison flows for the Niagara River to take into consideration changes in the long-term operation of the Great Lakes and diversions into and out of the Great Lakes basin. The most recent basis of comparison flows were determined for the period 1900 – 1989. For purposes of this analysis, flow data for the period 1900 – 1999 was collected and factored into the basis of comparison flows to provide a period of record of 100 years. This flow analysis was prepared in support of relicensing studies for the Project.

The average flow in the Niagara River for this 100-year period is approximately 212,000 cfs. For the period 1961-1999, when the Niagara Power Project was in operation, the average annual flow has been higher, at approximately 222,000 cfs. For the period before the project went into operation, flows averaged only about 206,000 cfs.

Figure 2 illustrates the average annual flow for each year in the 100-year period of flows used in these analyses, illustrating the variation that has occurred from year to year. It is evident that flow variation must be considered in any analyses of capacity and energy which may be marketed from this project.

The flows have a typical seasonal variation, with flows lowest in January, averaging about 198,000 cfs, and highest in May, averaging about 228,000 cfs. The flow data has also been organized into monthly flow duration curves, as shown on Figure 3, for purposes of these production studies. A flow duration curve illustrates the amount of time a flow of any magnitude has been equaled or exceeded. These flow duration curves are used to calculate generation at the Project in this study.

Figure 2

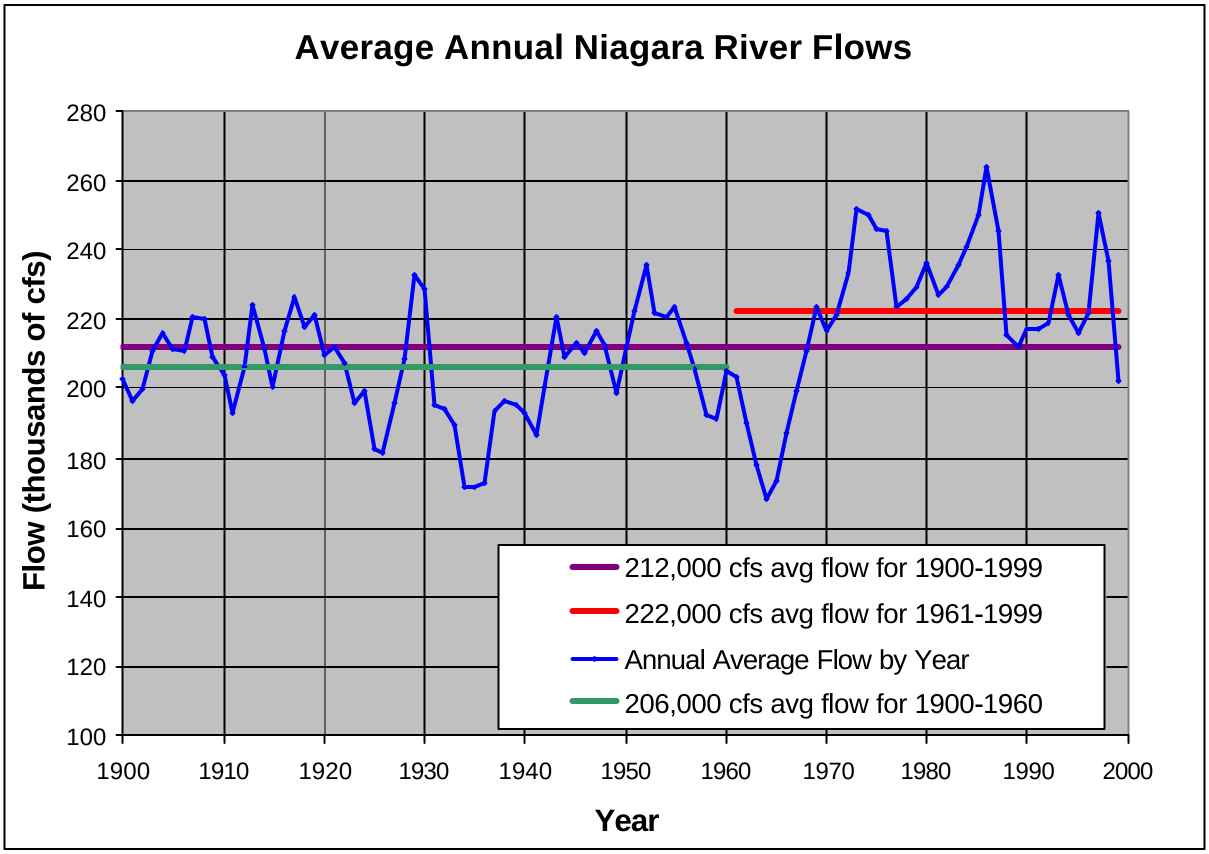
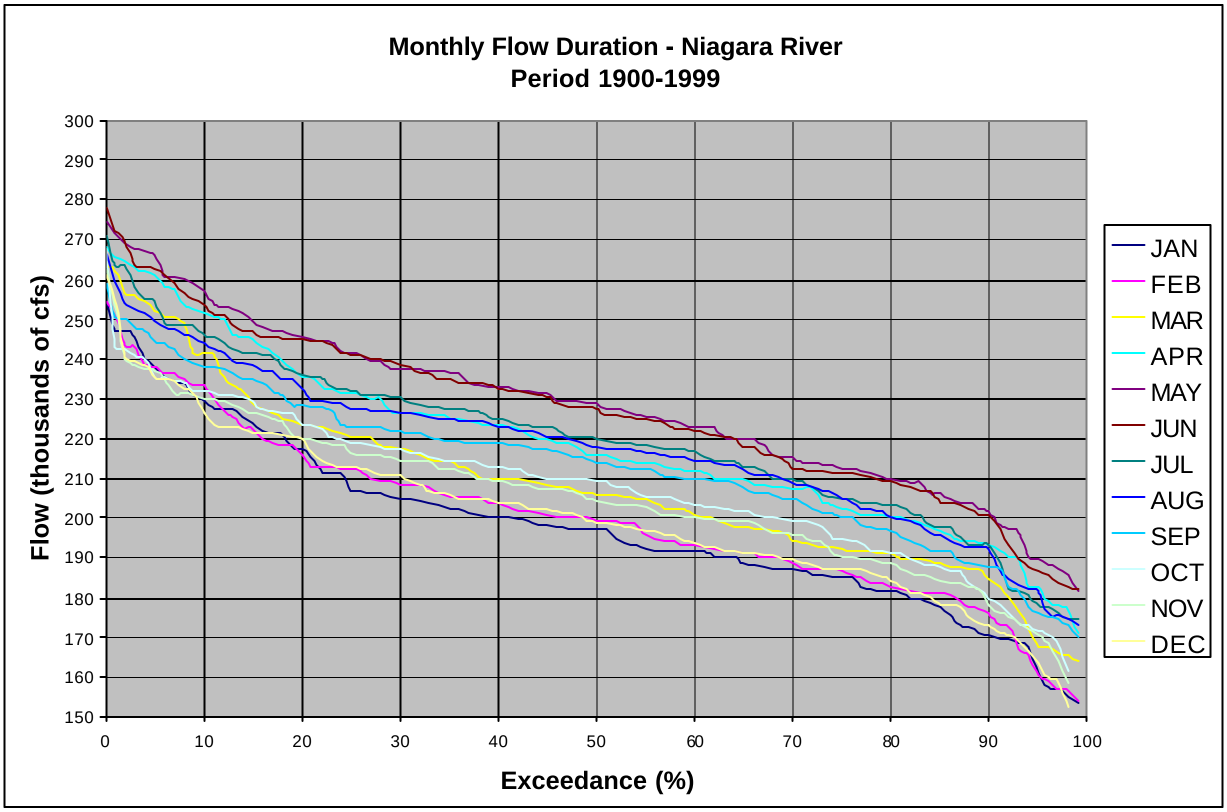


Figure 3



8. Performance of the Upgraded Turbines

The upgraded turbines at RMNPP were designed to allow an increase in the nameplate capacity of the units, which in turn will allow re-timing of production to peak demand periods, to improve efficiency and to provide for periodic overhauls of the major generation equipment.

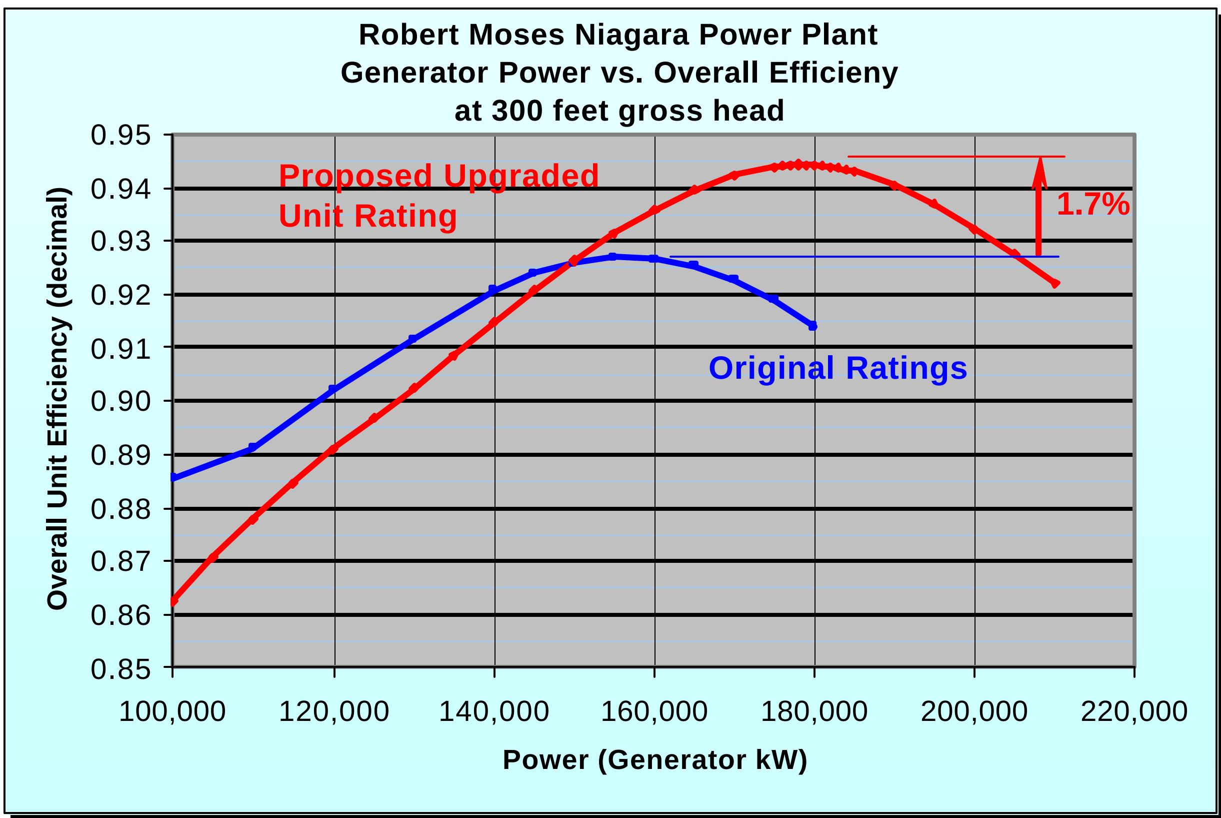
The peak efficiency of the units, including both the turbines and generators, has been increased from about 92.7% to about 94.4%, an increase of approximately 1.7%. This means that 94.4% of all the energy available in the flow and head at the plant can be converted to electricity when the units are operated at peak efficiency. River flows and power demand do not always permit operation at peak efficiency, but such operation is a goal. Figure 4 shows the efficiencies of the original and upgraded turbines plotted against power output. The efficiencies are shown for a head of 300 feet, which approximates the long-term average head at RMNPP.

The 1.7% efficiency increase represents a 1.7% increase in energy that can be produced from the same flows available to the Project. It also represents an increase of the firm capacity that can be provided of 1.7% of 1,880 MW, or 32 MW, since the nameplate capacity of the units has been sufficiently increased to allow operation at higher unit power levels. Similarly, the peaking capacity of the project has been increased by a proportional amount.

The efficiencies have been determined through tests which measure the flow, power and head on the units, referred to as Gibson Tests. These tests were conducted on several units at both the RMNPP and Ontario Power Generation's Sir Adam Beck Plant to assure equitable sharing of the flows of the river. The International Joint Commission is currently reviewing the proposed rating tables resulting from these tests.

The increase in efficiency results primarily from replacement of the turbine runners with new runners having a new blade design, and modifications to the turbine hydraulic passages. Some efficiency improvements also occurred in the generators as a result of improvements to the cooling system. The effect on efficiency of all modifications is shown on Figure 4.

Figure 4



9. Analyses of Customer Loads

The Power Authority's Marketing and Economic Development Business Unit analyzed the power usage patterns of the various customer groups served from the Niagara Power Project, and provided updated projections of customer load shapes. A load shape is a plot illustrating the power demand for each hour of the day. Customers generally do not demand their peak contracted power requirements at the same time each day, so daily load shapes were prepared for both peak weekday coincident loads and average weekday coincident loads for each month of the year.

Please refer to the November 2006 Niagara Load Study, attached to this report, for detailed information on customers, assumptions, and other parameters.

10. Analyses of the Ability of the Project to Meet Customer Loads

The following analyses examine the ability of the Project to provide power and energy to meet customer loads as determined in the Niagara Load Study.

The calculations performed first compare the peak daily customer loads to the maximum output the Project could provide under the flows available, for each month. The calculations assume that Lewiston Reservoir will be drawn down progressively through a weekly cycle, with partial re-filling each night and complete refilling over the weekend, so the cycle can repeat. Lewiston Reservoir is assumed to be 1/3 full for the calculations. While this limits the power that can be generated during the days at the LPGP, it also limits the pumping power required at night, so the energy analyses are not sensitive to the selection of reservoir level. As can be seen from the following analyses, capacity that meets the customer peak daily loads is generally achievable.

Calculations are then made to determine the energy required to support the 24-hour customer load profiles and the energy that can be produced based on available flows from the river. Analyses are performed for the range of flow exceedance values, again for each month.

Before presenting the results of these analyses, a summary tabulation of the steps and parameters included in the daily capacity calculation is provided in the next section, by illustrating calculation of the peaking capacity.

10.1 Calculation of Peaking Capacity

Table 1 summarizes the peaking capacity calculation for the Niagara Power Project together with the supporting flows and heads for summer and winter periods.

Low river flows at 95% exceedance have historically been used in such analyses, and are again are used in this analysis. The 95% exceedance flows are approximately 168,000 cfs during the non-tourist months and 181,000 cfs during the tourist months. As described in Section 4, a flow of 50,000 cfs is discharged over Niagara Falls during the non-tourist daytime periods and 100,000 cfs is discharged during daytime tourist periods. These flows must be subtracted from the river flows to determine flows available for generation. The available flow is divided between the U.S. and Canada, with other adjustments made for the effects of ice in the winter. The resulting U.S. entitlement flows available for generation are approximately 55,000 cfs during the daytime non-tourist period and 37,000 cfs during the daytime tourist period (see Table 1).

For peaking capacity calculations, flows available from LPGP are then determined and added, to obtain the net flow that is available to RMNPP. For a given flow and head, the power output of the RMNPP units can be determined from the tested performance of the units. Table 1 illustrates the capacity using the performance of the original units. The power output depends on the number of units through which the available flows are discharged, since power production is at a maximum when the units are operated near peak efficiency.

The headwater elevation is calculated using the average level of the Grass Island Pool of Elevation 561 feet. Conduit energy losses are then calculated to obtain the approximate forebay elevation at RMNPP. The tailwater elevation is determined using a relation of flow vs. elevation assuming average levels in Lake Ontario. Note that a combination of statistically low entitlement flows, but average levels of Lake Ontario and the Grass Island Pool have been used.

The weighted average peaking capacity based on the summer and winter capacity values shown on Table 1 is approximately 2,360 MW. The Power Authority has historically used 2,400 MW as the Project's peaking capacity.

Table 1
Peaking Capacity Summary
Prior to Upgrade
(Weekday Daytime Power Capability for a few hours each day)

	Non-Tourist Period (Winter)	Tourist Period (Summer)
Flow Exceedance	95%	95%
River Flow	168,000 cfs	181,000 cfs
Treaty-Required Falls Flow	50,000 cfs	100,000 cfs
Welland Canal Flows	7,000 cfs	7,000 cfs
Approximate NYPA Entitlement Flow for Generation	55,000 cfs	37,000 cfs
Typical Additional Falls Spills due to Ice	2,000 cfs	Not Applicable
Flow from Grass Island Pool Storage	5,000 cfs	5,000 cfs
Flow Available from LPGP	42,000 cfs	42,000 cfs
Net Day-time Flows Available for U.S. Production	100,000 cfs	84,000 cfs
Maximum discharge capability of RMNPP with 175 MW maximum power	96,000 cfs	95,000 cfs
Discharge that may be Used for Generation	96,000 cfs	84,000 cfs
Average RMNPP Headwater Level	553 feet	557 feet
Average RMNPP Tailwater Level	249 feet	250 feet
Average Gross Head at RMNPP	304 feet	307 feet
Number of RMNPP Units to Run for optimal efficiency	13 units	13 units
Flow Per RMNPP Unit	7,400 cfs	6,500 cfs
Reservoir Elevation (1/3 full)	632 feet	632 feet
Average Gross Head at LPGP	79 feet	75 feet
Power from RMNPP	2,275 MW	2,026 MW
Power from LPGP	240 MW	226 MW
Combined Capacity	2,515 MW	2,252 MW

10.2 Ability of Project to Follow Customer Loads

Analyses of the ability of the Project to follow a load profile were based on a similar calculation as illustrated above for the peaking capacity computation, with the addition of energy computations for weekdays and weekends.

Figures are presented to summarize the load profiles and ability of the Project to follow the load profiles for summer and winter periods, and for low and median flows. In this section, only weekday coincident load profiles are used, which provide a more conservative test of the Project's ability to meet the customer capacity and energy requirements.

Figure 5 illustrates January low flow conditions for 95% exceedance flows. The coincident peak customer load profile is plotted on the upper half of the figure in yellow, with a peak weekday load of about 2,100 MW. The peak capacity of the Project under these flow conditions is plotted for both the original and upgraded units, including estimates for the number of hours that the peak capacity could be maintained (see legend on the Figure). The peak capacity achievable by both the original and upgraded units exceeds the demand during these hours. Based on a daily energy production calculation including nighttime pumping requirements to support the on-peak generation, the nighttime capacity that the Project could provide is included in the plot. It is evident that for low flows in January, if the full peaking capability of the Project were utilized, the nighttime net generation would be very low. A capacity of 100 to 1,200 MW would be achievable as shown on Figure 5. It would be possible to increase net nighttime capacity above 100 MW, but at a reduction in the 1,200 MW value as illustrated for some of the hours. It is clear however that the capacity that could be provided at night is well below the customer load profile for most of the day, since flows are not sufficient to provide higher capacity for all hours of the day.

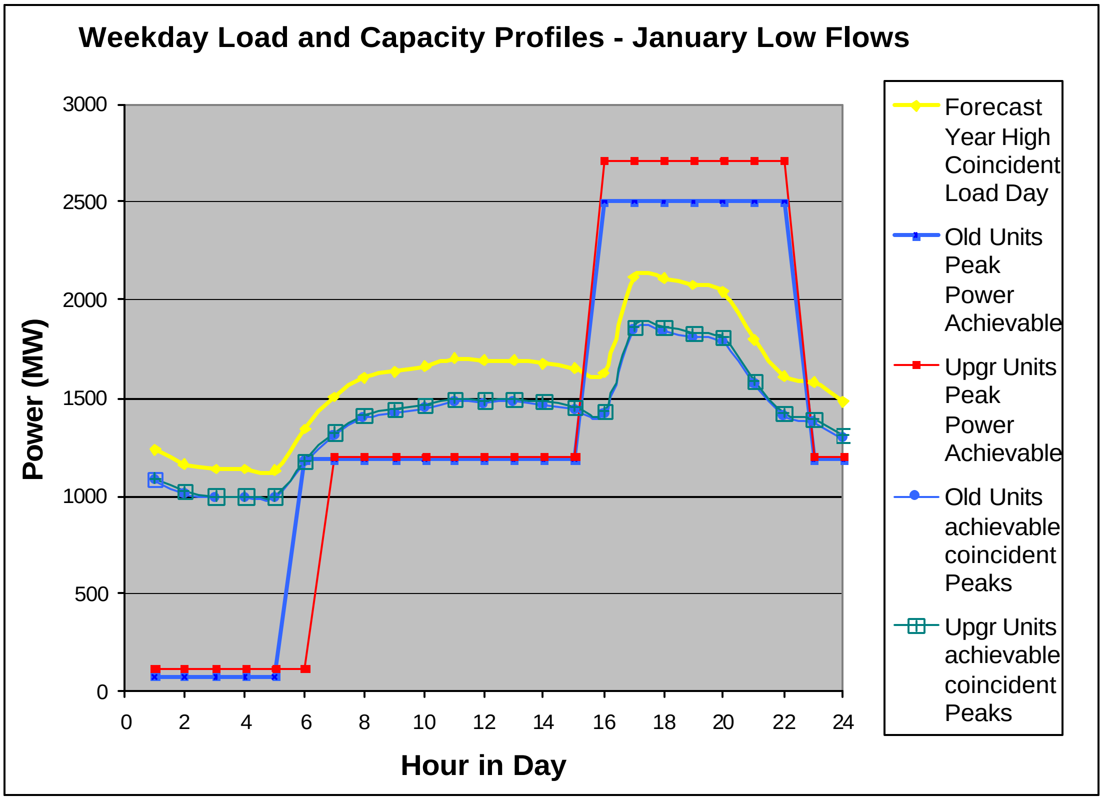
An estimate of the load profiles that could be followed by the Project with original and upgraded units is also included on the Figure. Under January low flow conditions, these plots illustrate the extent to which the Project cannot meet the customer load profile during the weekdays.

As described above, on weekends additional pumping must take place to refill Lewiston Reservoir. The customer average load profile for January weekends, and the ability of the Project to follow this load profile based on pumping energy requirements to refill the reservoir, are plotted on the lower half of Figure 5. It is apparent that under January low flow conditions, the Project cannot meet the weekend customer energy requirements, while the Project can achieve peaking capacity requirements for a few hours each weekday.

Figures 6, 7 and 8 illustrate the profiles for low flows in August (95% exceedance), and median (50% exceedance) flows in January and August, respectively. The next section summarizes the ability of the Project to meet customer loads for all months.

As noted above, the ability of the Project to follow load profiles was examined for both the original and upgraded RMNPP units. The higher efficiency of the upgraded units provides a modest increase in production during all hours of the day, and the effect of efficiency improvements is factored into the analyses. On the figures, the effect of the efficiency improvements is seen as the small difference between the plots for the achievable coincident peaks for the original and upgraded units.

Figure 5 – Profiles for January Low Flows



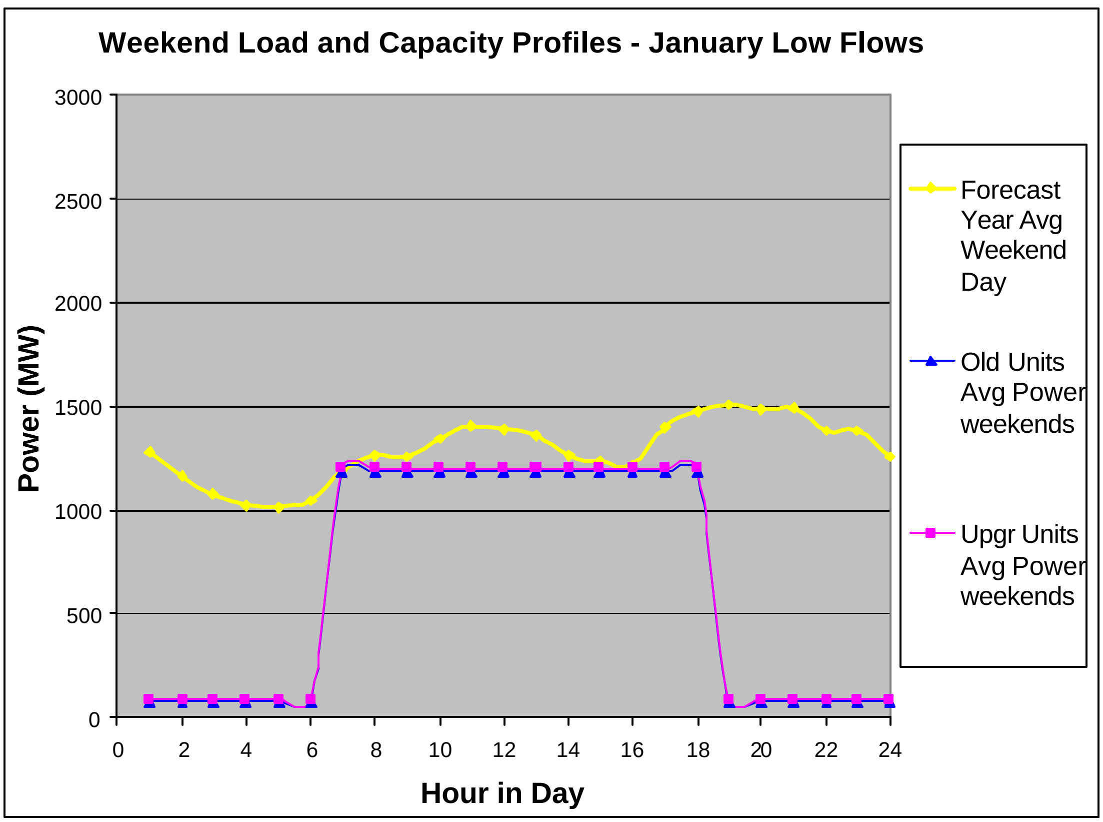
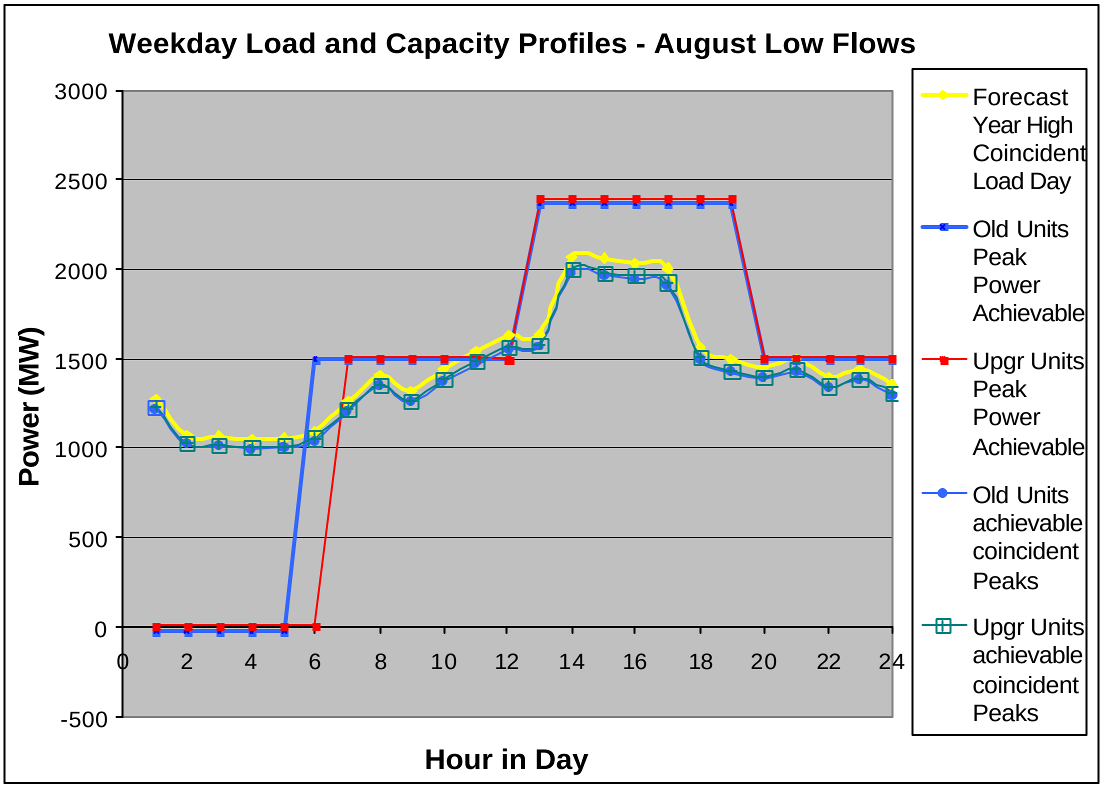


Figure 6 – Profiles for August Low Flows



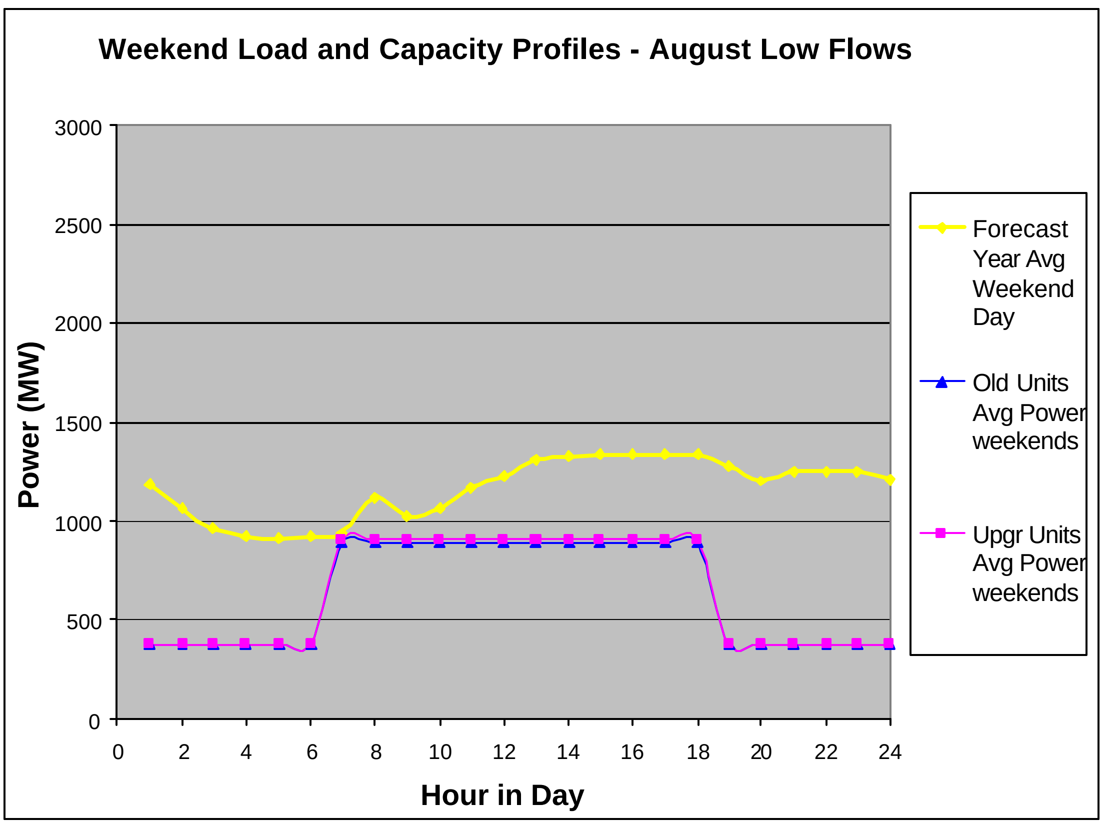
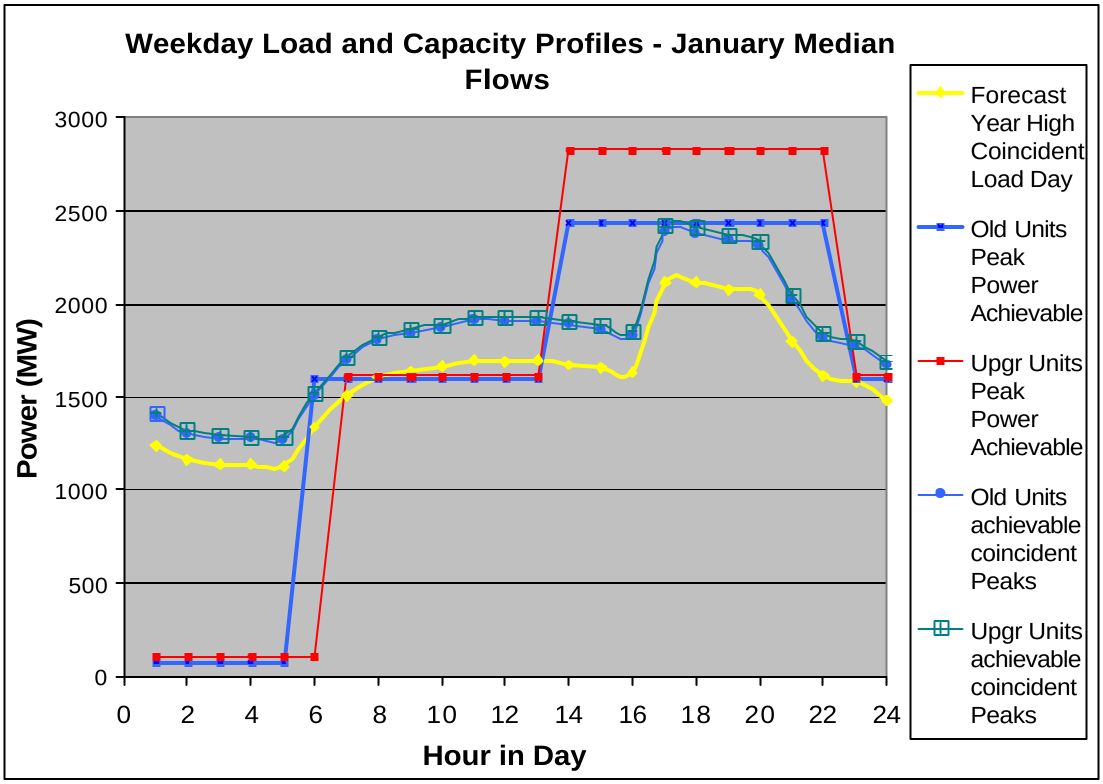


Figure 7 – Profiles for January Median Flows



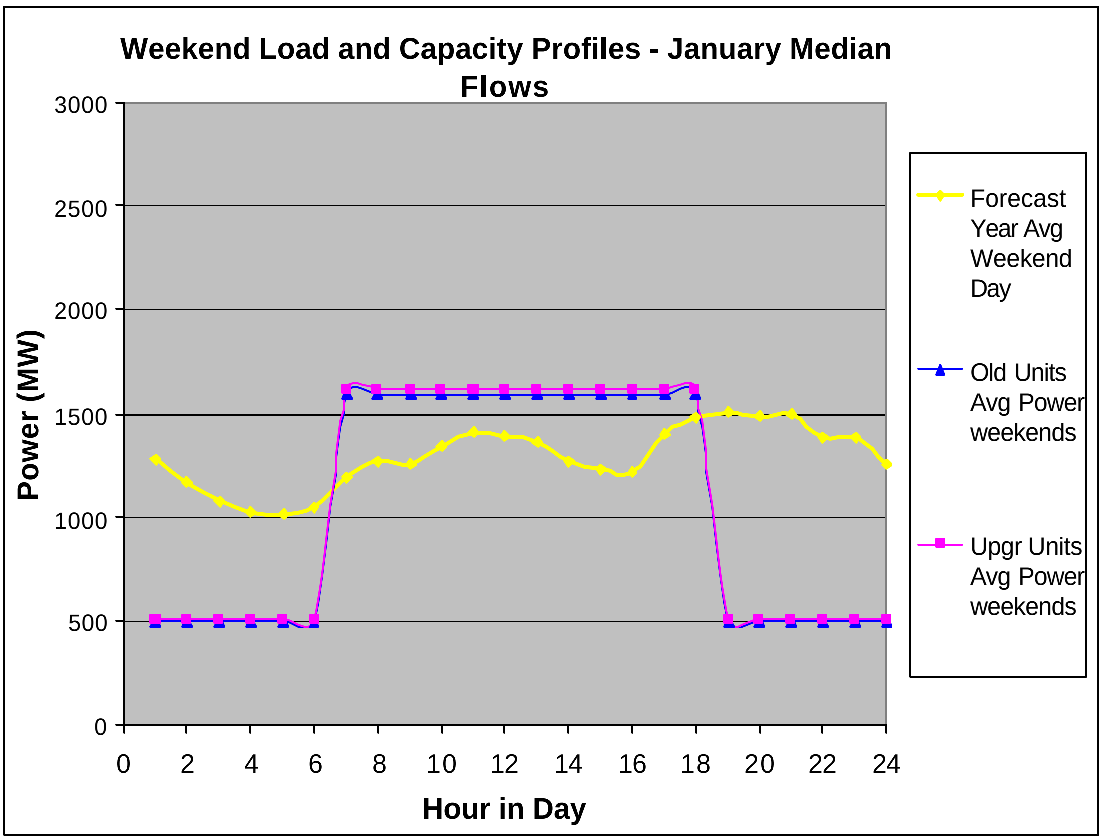
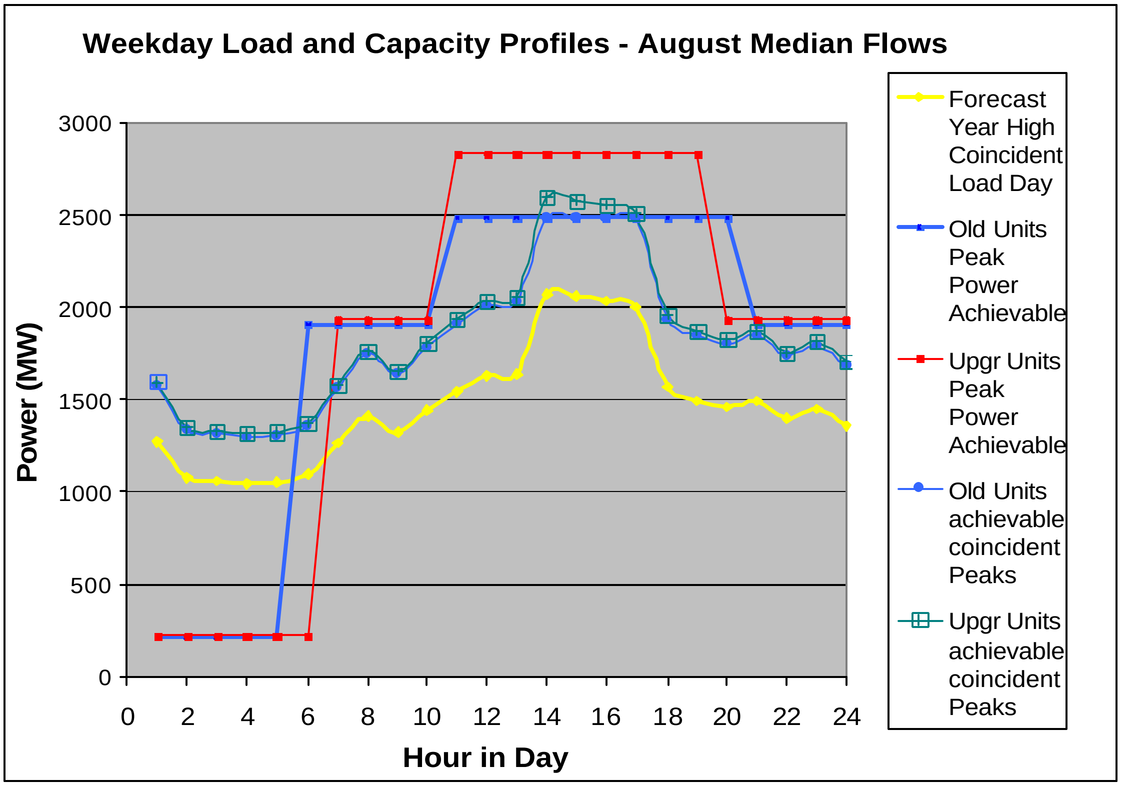
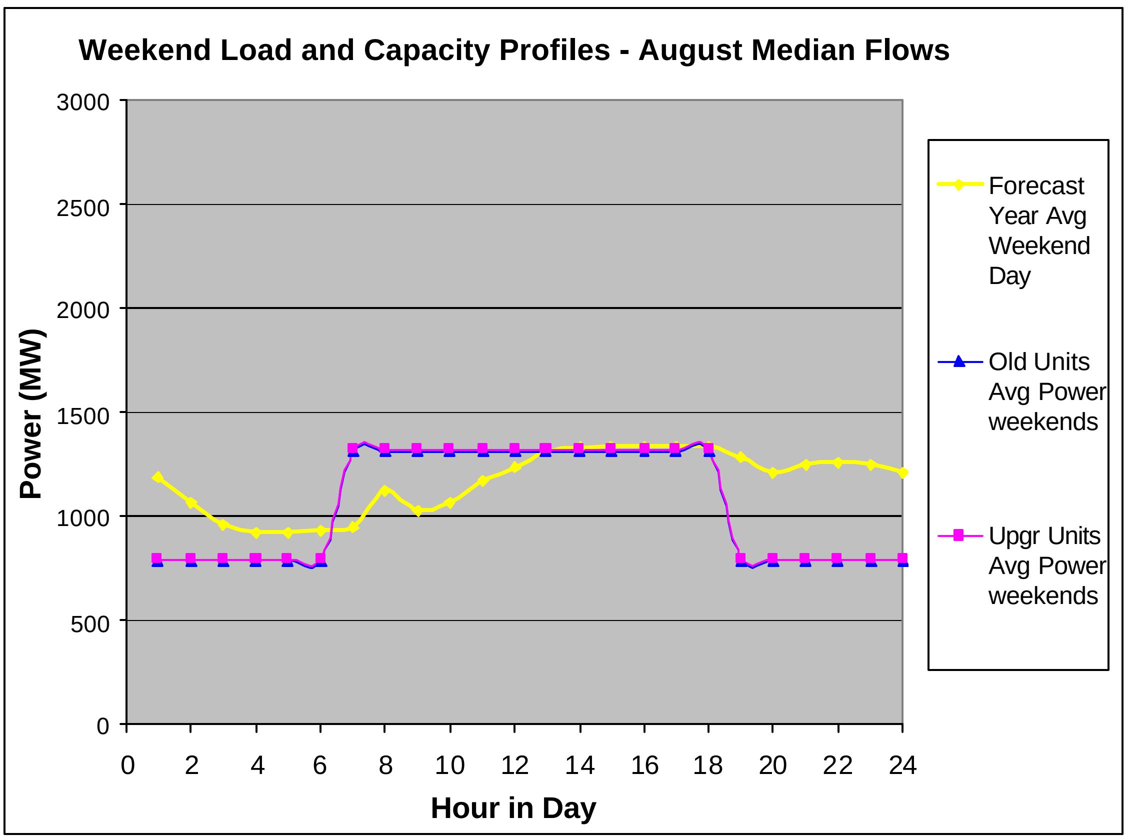


Figure 8 – Profiles or August Median Flows





11. Curtailment

The load profile analyses described in Section 10 were completed for all months and the range of flow values from the flow duration curve of Figure 3 to quantify the extent and frequency of the deficiency in energy that would result using the updated flow records and unit performance values. In these analyses, a shortfall is calculated as the percentage of energy required by the load profile that could not be provided. This shortfall may also be referred to as the curtailment. Computations were performed for both the peak coincident load profiles and the average load profiles.

To summarize these analyses, a tabulation of the energy required by the load profiles was prepared, along with tabulations of the energy that could be produced, for each month and flow. The flow values were also tabulated. Table 2 summarizes these results.

Table 2 shows that under low 95% exceedance flows the Project cannot meet the peak coincident load profiles, and under 85% exceedance flows cannot meet the load profiles in about ½ of the months. Under higher 75% exceedance flows, the Project still cannot meet the requirements of energy defined by the peak coincident load profiles in several of the months. It is estimated overall that the flows are sufficient to meet the energy requirements defined by the average customer load profiles about 85% of the time.

The energy shortfall values were plotted against river flows, as illustrated on Figures 9 and 10, for average contract demand and peak coincident contract demand, respectively.

In recent years (2000-2006), the Project has periodically been unable to meet customer energy requirements. Actual experience in recent years has therefore been reviewed to determine the reasonableness of the above predictions. Figure 11 shows the actual energy curtailments determined for the 2000-2006 period, for which curtailment records were available. Comparing Figure 11 to Figures 9 and 10 shows that for the same river flow the predicted energy shortfall agrees closely with the actual shortfall. On these figures, curtailment is defined so that a positive value of indicates a surplus, and a negative value indicates a shortfall.

The summer flows available for generation are lower due to treaty required flows over Niagara Falls, but the river flow is higher and there are no ice related spills, so the curtailment in the summer may actually be less. However, curtailment depends not just on the Project's output, but on the customer load shapes. In the summer months, the energy requirement of the customer load shapes tends to be less than for the winter. Table 2 shows curtailments are generally less during the summer months than the winter months.

Table 2
Niagara Project Output vs. Contract Demand - Summary
(Energy stated in MWHRS)

		Based on Coincident Peaks		**95% Flow Exceedance**				**85% Flow Exceedance**			
		Weekday Daily Energy Required	Weekend Daily Energy Required	Flow	Weekday Energy Produced	Weekend Daily E Produced	Shortfall (%)	Flow	Weekday Energy Produced	Weekend Daily E Produced	Shortfall (%)
Non-Tourist	Jan	38,386	30,915	161	33,824	15,472	-21	177	38,375	20,071	-9
	Feb	39,759	32,212	161	33,703	15,351	-24	181	39,404	21,060	-9
	Mar	38,143	30,568	168	35,782	17,294	-15	189	41,330	23,086	0
Tourist Period	Apr	37,529	29,819	183	34,262	15,739	-18	197	38,240	19,696	-7
	May	35,851	26,528	190	36,269	17,716	-7	206	40,840	22,248	7
	Jun	34,718	28,809	186	35,342	16,793	-9	204	40,247	21,675	6
	Jul	35,597	26,529	178	32,995	14,400	-16	198	38,480	19,933	1
	Aug	35,215	27,962	182	33,925	15,405	-14	196	37,936	19,281	-2
	Sep	35,189	25,009	176	32,448	13,891	-16	192	36,823	18,246	-2
	Oct	36,700	29,109	172	31,111	12,579	-25	188	35,752	17,185	-12
Non-Tourist	Nov	36,161	29,976	171	36,640	18,206	-9	184	40,314	21,924	2
	Dec	38,541	30,007	164	34,570	16,199	-19	178	38,636	20,326	-7

		Based on Average Peaks		**95% Flow Exceedance**				**85% Flow Exceedance**			
		Weekday Daily Energy Required	Weekend Daily Energy Required	Flow	Weekday Energy Produced	Weekend Daily E Produced	Shortfall (%)	Flow	Weekday Energy Produced	Weekend Daily E Produced	Shortfall (%)
Non-Tourist	Jan	37,449	30,915	161	33,824	15,472	-20	177	38,375	20,071	-7
	Feb	38,464	32,212	161	33,703	15,351	-22	181	39,404	21,060	-7
	Mar	37,059	30,568	168	35,782	17,294	-13	189	41,330	23,086	3
Tourist Period	Apr	36,053	29,819	183	34,262	15,739	-15	197	38,240	19,696	-4
	May	32,752	26,528	190	36,269	17,716	0	206	40,840	22,248	15
	Jun	33,510	28,809	186	35,342	16,793	-7	204	40,247	21,675	9
	Jul	32,829	26,529	178	32,995	14,400	-11	198	38,480	19,933	7
	Aug	33,473	27,962	182	33,925	15,405	-10	196	37,936	19,281	2
	Sep	34,015	25,009	176	32,448	13,891	-14	192	36,823	18,246	0
	Oct	35,346	29,109	172	31,111	12,579	-23	188	35,752	17,185	-9
Non-Tourist	Nov	36,161	29,976	171	36,640	18,206	-9	184	40,314	21,924	2
	Dec	36,735	30,007	164	34,570	16,199	-16	178	38,636	20,326	-4

Table 2, continued
Niagara Output vs. Contract Demand - Summary
(Energy stated in MWHRS)

Based on Coincident Peaks

		75% Flow Exceedance				50% Flow Exceedance				5% Flow Exceedance			
		Flow	Weekday Energy Produced	Weekend Daily E Produced	Shortfall (%)	Flow	Weekday Energy Produced	Weekend Daily E Produced	Shortfall (%)	Flow	Weekday Energy Produced	Weekend Daily E Produced	Shortfall (%)
Non-Tourist	Jan	185	40,609	22,243	-2	197	43,748	25,463	6	238	53,768	36,181	34
	Feb	187	40,889	22,549	-5	200	44,413	26,115	4	238	53,768	36,181	30
	Mar	192	42,422	24,179	3	206	46,014	27,841	13	252	55,628	39,739	42
Tourist Period	Apr	202	39,798	21,215	-2	216	43,546	24,948	8	261	54,693	36,734	40
	May	213	42,625	24,049	12	229	47,083	28,463	26	266	55,316	37,997	52
	Jun	211	42,273	23,702	12	228	46,716	28,103	25	263	54,835	37,134	51
	Jul	205	40,456	21,878	6	220	44,622	26,011	19	254	53,754	35,022	47
	Aug	205	40,485	21,906	6	218	44,109	25,415	17	250	52,506	33,814	42
	Sep	200	39,219	20,656	5	214	43,060	24,475	17	245	51,258	32,587	42
	Oct	195	37,699	19,033	-6	210	41,854	23,173	6	236	48,837	30,182	26
Non-Tourist	Nov	191	41,909	23,669	7	204	45,540	27,365	17	237	53,661	35,979	41
	Dec	187	40,948	22,699	-1	199	44,228	25,917	8	235	53,406	35,497	34

Based on Average Peaks

		75% Flow Exceedance				50% Flow Exceedance				5% Flow Exceedance			
		Flow	Weekday Energy Produced	Weekend Daily E Produced	Shortfall (%)	Flow	Weekday Energy Produced	Weekend Daily E Produced	Shortfall (%)	Flow	Weekday Energy Produced	Weekend Daily E Produced	Shortfall (%)
Non-Tourist	Jan	185	40,609	22,243	-1	197	43,748	25,463	8	238	53,768	36,181	37
	Feb	187	40,889	22,549	-3	200	44,413	26,115	7	238	53,768	36,181	33
	Mar	192	42,422	24,179	6	206	46,014	27,841	16	252	55,628	39,739	45
Tourist Period	Apr	202	39,798	21,215	1	216	43,546	24,948	12	261	54,693	36,734	45
	May	213	42,625	24,049	20	229	47,083	28,463	35	266	55,316	37,997	63
	Jun	211	42,273	23,702	15	228	46,716	28,103	29	263	54,835	37,134	55
	Jul	205	40,456	21,878	13	220	44,622	26,011	27	254	53,754	35,022	56
	Aug	205	40,485	21,906	10	218	44,109	25,415	22	250	52,506	33,814	48
	Sep	200	39,219	20,656	8	214	43,060	24,475	20	245	51,258	32,587	46
	Oct	195	37,699	19,033	-4	210	41,854	23,173	9	236	48,837	30,182	30
Non-Tourist	Nov	191	41,909	23,669	7	204	45,540	27,365	17	237	53,661	35,979	41
	Dec	187	40,948	22,699	3	199	44,228	25,917	12	235	53,406	35,497	39

Figure 9

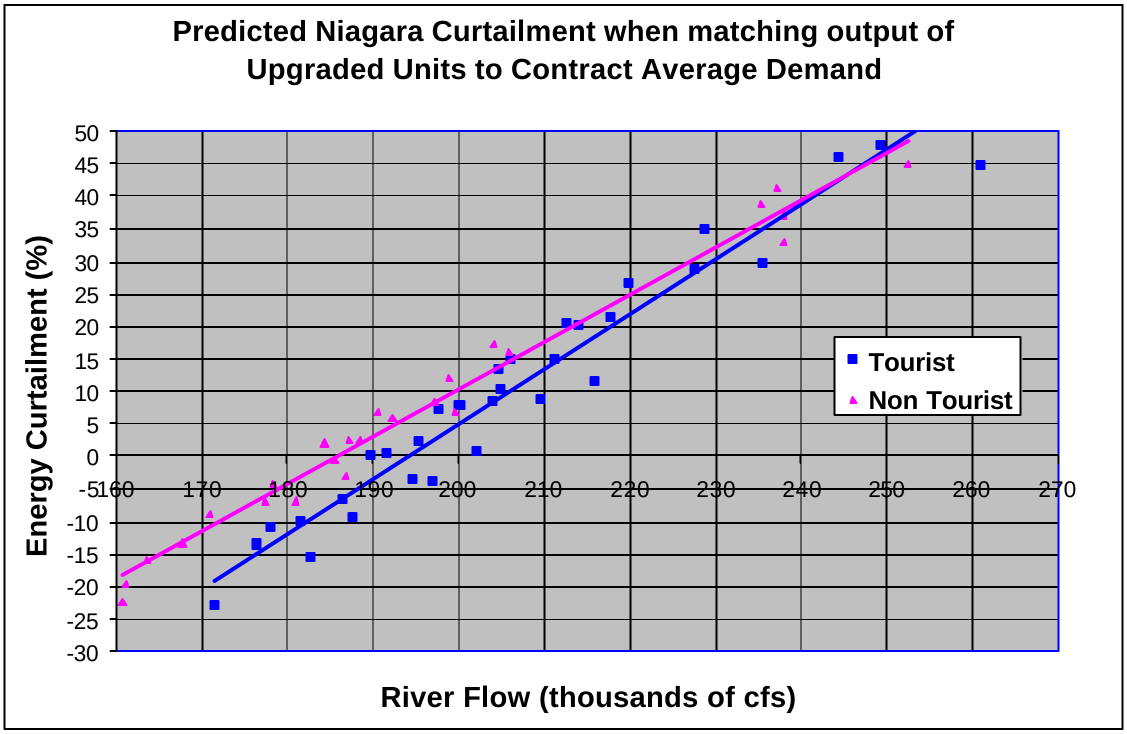


Figure 10

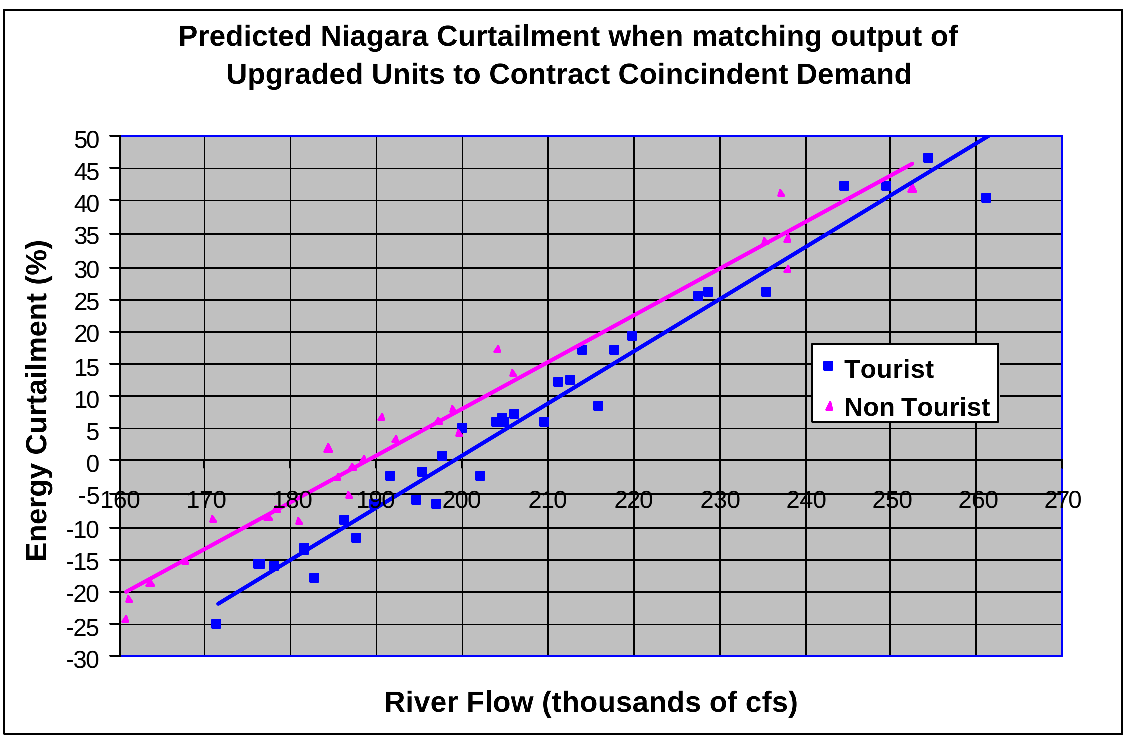
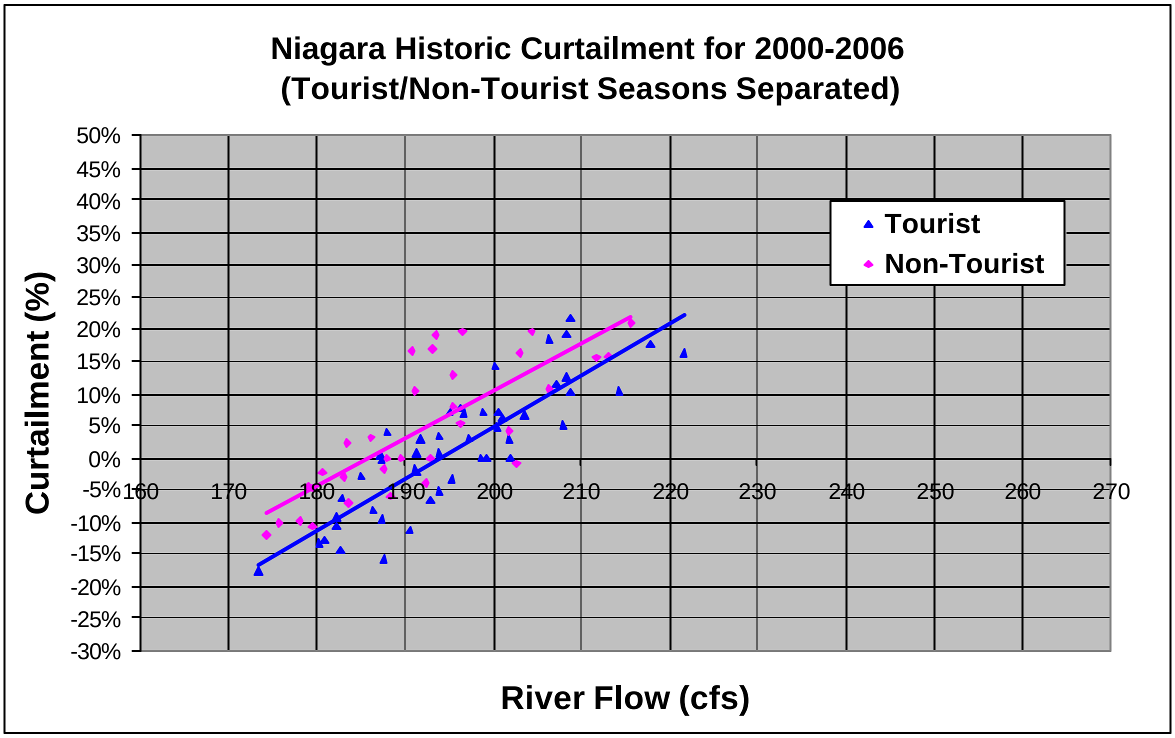


Figure 11



12. Summary and Conclusions

Analyses were performed using updated river flow records and the performance of the upgraded units at RMNPP to determine the ability of the Project to follow customer load profiles.

Based on the updated flow records and the higher efficiency of the upgraded units, the ability of the Project with the upgraded units to meet customer load profiles was examined. It is concluded the Project cannot meet the energy requirements defined by the average peak load profiles about 15% of the time. In some months, the curtailment rate would be about 25%. This is a lower curtailment rate than the "somewhat less than 3 out of 4 years" [1] estimated in the 1970s. While the actual 1970s calculations are not available to us to review, it is reasonable to postulate the lower rate of predicted curtailment in the present analyses is the result of slightly higher flows in the longer flow record and updated analyses of customer load.

1. Testimony of John W. Boston before the Federal Power Commission, Docket No. E-8746, State of Vermont Public Service Board v. Power Authority of the State of New York

While the longer flow record indicates somewhat higher flows and possibly lower curtailment on average, the flows have considerable variation (see Figure 2) and for periods of several years the curtailments could be greater than the average values based on the long term hydrologic record.

The efficiency of the upgraded turbine-generator units at RMNPP has been increased by approximately 1.7%, allowing increased energy generation and capacity for the same flows available from the river. The increase in firm capacity achieved through the increase in efficiency is therefore 1.7% of 1,880 MW, or 32 MW. Increasing the firm capacity of the Project by 32 MW (to 1,912 MW) would result in the same likelihood of achieving customer load profiles with the upgraded units as would occur using the original units with a firm capacity of 1,880 MW.

Similarly, the 2,400 MW peaking capacity value would also increase by approximately 1.7%, to 41 MW, for an increase of 9 MW of peaking capacity. This results because under the low river flow conditions used for the peaking capacity determination, the RMNPP units would still operate close to their peak efficiency, hence the 1.7% increase remains applicable. The best efficiency operating point is at approximately 185 MW, below the nameplate capacity of the units, so that the higher nameplate capacity does not enter into the calculations.

The increase in nameplate capacity of the RMNPP units resulting from the upgrade does not provide for an increase in firm or peaking capacity, since firm and peaking capacity are limited by flows available from the river under adverse flow conditions.

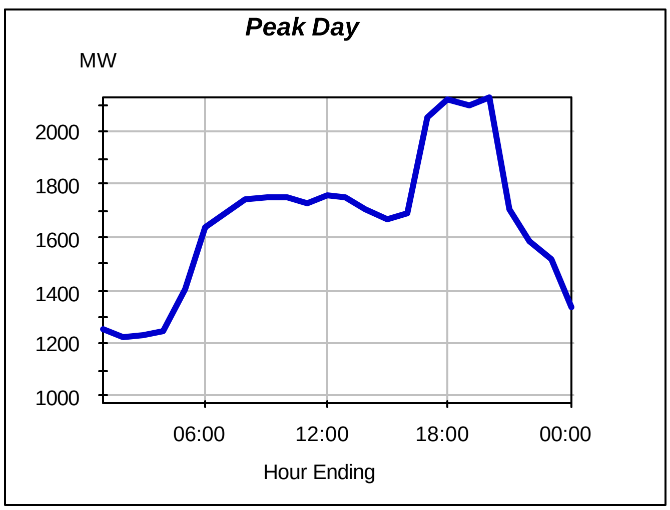
13. References

Application for New License and Preliminary Draft Environmental Assessment, Niagara Power Project FERC No. 2216, New York Power Authority (August 2005). http://www.ferc.gov/docs-filing/elibrary.asp

Lupo, M. and E. Travis, Niagara Load Study Report, November 2006.

Marketing and Economic Development

Niagara Load Study



Prepared By:
Customer Load Forecasting
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Egle Travis

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New York Power Authority

Niagara Load Study

Executive Summary

The purpose of this Load Study was to determine the usage patterns of the customers served under the various Power Programs from the Power Authority's Niagara Project. Recent history has shown that there are various customer movements within each of the Power Programs and that usage patterns vary because of other specific reasons differing for each Power Program, including changes in diversity, contract demands and load factor.

Each Power Program usage pattern was developed for a base year and a forecast year. When a Power Program's base year usage pattern did not reflect its full allocation of contract demand, the forecast year was then projected to fully allocated contract demand amounts. Further, new relicensing-related allocations (58 MW) and other necessary adjustments were modeled in the forecast year.

Both the base year and forecast year usage patterns were developed on an hourly basis by month. The monthly usage patterns independently reflect the seasonal nature of each Power Program load, while the hourly usage pattern reflects the time differentiated nature of the load. Collectively the monthly and hourly usage patterns of each Power Program load reflect the individual intra-class Power Program diversity and the inter-class diversity among all of the Power Programs.

Specifically, the development of the base year and forecast year monthly and hourly load estimates was completed with a focus on on-peak and off-peak energy usage and load factor. This was necessary as the Niagara Project is both a base load and pumped storage hydro facility and a reasonable estimate of the time differentiated customer requirements would provide a comparison mechanism to estimated generation under various low to high hydro flow conditions.

The base year was projected to be winter peaking at 2,192 MW with annual usage of 12,935 GWh and a 67.4% load factor. The peak load is expected to decline slightly to 2,127 MW in the forecast year with a similar reduction in energy to 12,247 GWh and load factor to 65.7%. The overall reductions from the base year to the forecast year are primarily attributable to change in the Rural and Domestic and Replacement Power Programs with respect to either the size of the program or reduction in overall load factor.

Existing Contract Demands

The Niagara Project provides power and energy to the five major Power Programs listed in Table 1. Table 1 shows the program name, the base year contract demand and the forecast year contract demand.

Program	Program Name	Contract Demand (MW) Base Year	Forecast Year
I	Niagara Rural and Domestic		
	Firm	301	187
	Peaking	360	360
II	Expansion & Replacement Power		
	Expansion Power (EP)	250	250
	Replacement Power (RP)	445	445
III	Niagara Municipals & Coops.	752	752
IV	Niagara Neighboring States Bargaining Agents		
	Firm	188	188
	Peaking	40	40
V	New Re-licensing Customers	0	58
	Program Totals	2,336	2,280

Table 1 – Programs Receiving Niagara Hydro Power

The base year contract demand totaled 2,336 MW with a power type breakdown of 1,936 MW of firm contract demand and 400 MW of peaking contract demand. Compared to the current Niagara project rating of 2,280 MW which consists of 1,880 MW of firm marketable capacity and 400 MW of peaking capacity it was determined that firm contract demand was over-allocated by 56 MW.

In developing the forecast year data, certain adjustments were made for known allocation changes resulting from the recently concluded relicensing settlement agreements. With the effective date of the new license expected to coincide with the expiration of the Niagara Rural and Domestic contracts, it has been assumed that the 58 MW of firm contract demand allocations provided for in the various Niagara relicensing settlement agreements would be served in the forecast year from the block of power currently sold to the Rural and Domestic customers.

As noted above, the current firm contract demand totals (1,936 MW) exceed the firm marketable capacity of the project (1,880 MW) by 56 MW. The firm marketable output amount was determined in a 1976 proceeding before the Federal Power Commission (now FERC) in Docket No. E-8746, where the Authority was directed to use 1,880 MW for firm allocation purposes.

The balance of the Power Program contract demands will remain unchanged in both the base year and forecast year.

It is important to note that in the base year several Power Program customers did not utilize their full allocations. Adjustments were made in the forecast year such that hourly projections were estimated at full contract demand usage levels. These adjustments were made for Expansion Power, Municipal and Cooperatives, and Neighboring State Peaking power customers.

The general load study assumption and specific contract demand, load factor and diversity assumptions are more fully documented in the Load Study Assumptions section of this report.

Base Year Hourly Loads

The base year hourly forecast uses data for the twelve month period ending June 30, 2006. This study period represented the most current data available at the time of the study. It was determined that the base year closely reflected current power allocations, and was consistent with corporate records, including wholesale billing and SAP Business Warehouse records. Available hourly interval load data from the Clark Energy Center Data Warehouse, NYISO Billed Load data and underlying customer power contract provisions were also reviewed for consistency in the load study.

One such contract provision warranted adjustment to the hourly data. Hydro curtailment adjustments were required because of low water flow conditions experienced during certain months of the base year. The effected hourly loads were analyzed at the lowest level of granularity and hourly loads increased as appropriate such that the adjusted actual load was stated at the “pre-curtailment” level.

In general, for the forecast year hourly load data was developed at several levels of granularity. These levels included the Power Program, sub-grouping within each Power Program or segments of load within each Power Program subgroup level. These levels of granularity and other salient aspects of the customer loads are more fully described in the “Assumptions” section of the report.

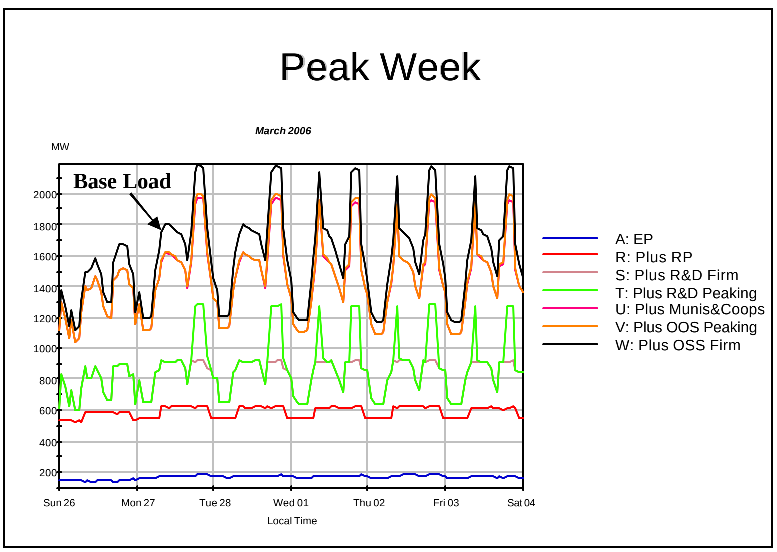


Figure 1 – Base Loads

Figure 1 displays the “pre-curtailment” adjusted base year load at the Power Program level for the peak week. The hourly data was used to generate average weekday and weekend load shapes for use in the Load Study.

Forecast Year Hourly Loads

The "pre-curtailment" base year hourly loads were combined with information regarding anticipated future contract demands and load factor to project the forecast year hourly loads. Then "new" Re-licensing customer loads were estimated to complete the forecast year. The aggregate base year and forecast year peak week hourly loads are presented in Figure 2.

As shown in Figure 2, the forecast is slightly lower than the base load. This change is primarily the result of Power Program withdrawals and load shifts from higher load factor to lower load factor customer usage patterns.

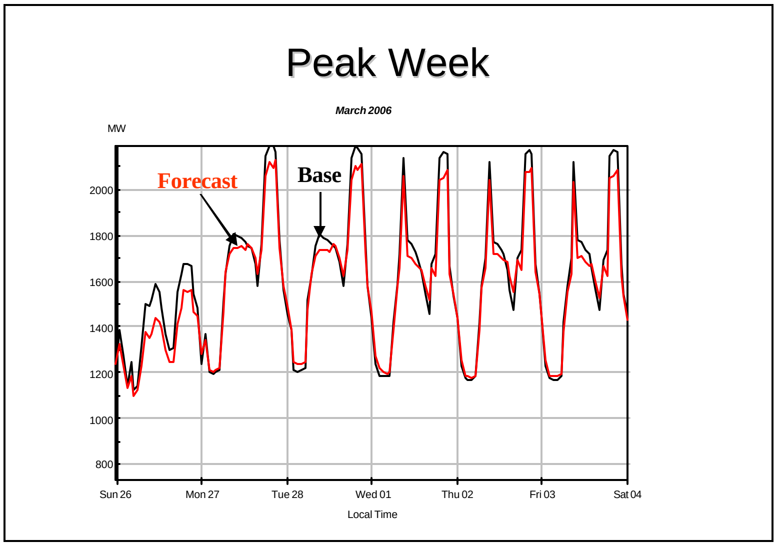


Figure 2 – Base and Forecasted Load

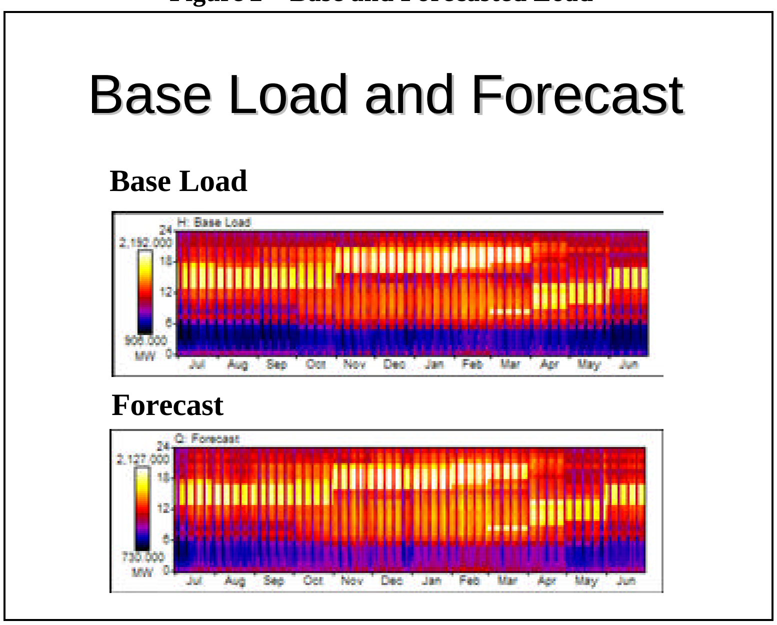


Figure 3 – Base Load and Forecast

Figure 3 presents the full year of base and forecasted load. The figure is displayed with time of day on the y-axis, day of the year on the x-axis and magnitude of load shown as a color gradient with low levels of demand in the black-blue spectrum and high levels of demand in the yellow-white spectrum. From these prints we can see that relatively low levels of load (approximately 900 MW) occur during the six-hour early morning period with increased load displayed throughout the remainder of the day. The highest loads occur during the early evening periods of the winter months. Summer loads are slightly lower during the off-peak hours while reaching similar levels of magnitude during on-peak hours. The summer load peaks in the early to mid afternoon period.

Detailed Forecast Results

Detailed forecast results were derived from the development of specific demand and energy attributes which included sum of the billed demands, non-coincident peak demand, coincident peak demand, total energy and on-peak and off-peak energy. Other information was reviewed to insure reasonableness and sanity checking was conducted which compared the hourly loads against wholesale billing, underlying Power Contracts and other marketing records.

Demand and Energy Characteristics

Tables 2 and 3 present summaries of the annual and monthly demand and energy usage characteristics associated with the base year and the forecast year. The tables present the monthly and annual usage, the time and amount of the monthly and annual coincident peak demand and average demand and the monthly and annual load factor.

The base year annual energy use was approximately 12,936 GWh with a corresponding annual maximum demand of 2,192 MW. The monthly usage ranges from a low of 1,004 GWh in June to a high of 1,138 GWh in January. The base year annual load factor is 67.4% with monthly load factors ranging from a low of 67.5% in July to a high of 71.9% in February.

Base Year					
Month	Energy (MWh)	Timing of the Coincident Peak	Coincident Peak (MW)	Average Demand (MW)	Load Factor
Jul-05	1,056,427	Mon Jul 25, 2005 3:00PM	2,103	1,420	67.5%
Aug-05	1,068,078	Thu Aug 4, 2005 2:00PM	2,108	1,436	68.1%
Sep-05	1,022,248	Tue Sep 13, 2005 3:00PM	2,038	1,420	69.7%
Oct-05	1,096,180	Tue Oct 25, 2005 2:00PM	2,051	1,473	71.8%
Nov-05	1,085,193	Thu Nov 17, 2005 7:00PM	2,162	1,507	69.7%
Dec-05	1,125,868	Wed Dec 14, 2005 7:00PM	2,154	1,513	70.2%
Jan-06	1,137,630	Thu Jan 26, 2006 7:00PM	2,168	1,529	70.5%
Feb-06	1,059,365	Mon Feb 27, 2006 7:00PM	2,192	1,576	71.9%
Mar-06	1,136,291	Fri Mar 3, 2006 8:00PM	2,173	1,527	70.3%
Apr-06	1,074,143	Wed Apr 5, 2006 11:00AM	2,097	1,492	71.1%
May-06	1,070,207	Wed May 31, 2006 2:00PM	2,068	1,438	69.5%
Jun-06	1,003,920	Thu Jun 22, 2006 5:00PM	2,042	1,394	68.3%
Annual	12,935,551	Mon Feb 27, 2006 7:00PM	2,192	1,477	67.4%

Table 2 – Demand and Energy Usage Characteristics: Base Year

For the forecast, the annual energy use is expected to drop by approximately 5.3% to 12,248 GWh with a corresponding 3.0% drop in maximum demand to 2,127 MW. The forecast shows a slight decline of the annual load factor from 67.4% to 65.7%. These changes are primarily attributable to assumed reductions in Replacement Power load factor.

Forecast Year					
Month	Energy (MWh)	Timing of the Coincident Peak	Coincident Peak (MW)	Average Demand (MW)	Load Factor
July	954,709	Weekday 4PM	2,075	1,283	61.8%
August	993,570	Weekday 2PM	2,072	1,335	64.5%
September	973,418	Weekday 5PM	2,012	1,352	67.2%
October	1,033,875	Weekday 2PM	1,996	1,390	69.6%
November	1,035,351	Weekday 7PM	2,122	1,438	67.8%
December	1,078,223	Weekday 7PM	2,120	1,449	68.4%
January	1,102,110	Weekday 5PM	2,118	1,481	69.9%
February	1,027,125	Weekday 9PM	2,127	1,528	71.8%
March	1,096,886	Weekday 9PM	2,099	1,474	70.2%
April	1,019,247	Weekday 2PM	2,071	1,416	68.3%
May	965,520	Weekday 2PM	2,049	1,298	63.3%
June	967,688	Weekday 5PM	2,035	1,344	66.0%
Annual	12,247,723	Weekday 9PM	2,127	1,398	65.7%

Table 3 – Demand and Energy Usage Characteristics: Forecast Year

On-Peak and Off-Peak Energy

An important aspect of the load is the on-peak/off-peak energy distribution. Tables 4 and 5 summarize the monthly on-peak/off-peak energy distribution for the base year and forecast year. In this analysis, the on-peak hours are defined as weekdays, excluding holidays for the 16-hour period encompassing hour ending 8am through hour ending 11pm with all other hours defined as off-peak[1].

The tables present the monthly use, maximum demand and load factor for the respective on-peak and off-peak hours. The summary displays the percentage of on-peak and the percentage of off-peak energy use. For the base year, the annual on-peak energy use was 53.3% of the total with the remaining 46.7% consumed during off-peak hours. On a monthly basis, the on-peak energy use ranged from a low of 48.6% in November to a high of 56.3% in March. The annual on-peak load factor was 77.6% compared to an annual off-peak load factor of 59.5%.

Base Year									
	On-Peak			Off-Peak			Summary		
Month	Monthly Use (MWh)	Coincident Peak (MW)	Load Factor (%)	Monthly Use (MWh)	Coincident Peak (MW)	Load Factor (%)	Total Monthly Use (MWh)	Percent On-Peak (%)	Percent Off-Peak (%)
Jul-05	536,211	2,103	79.7%	520,217	1,538	79.8%	1,056,427	50.8%	49.2%
Aug-05	609,473	2,108	78.6%	458,605	1,541	79.1%	1,068,078	57.1%	42.9%
Sep-05	553,912	2,038	80.9%	468,336	1,504	81.1%	1,022,248	54.2%	45.8%
Oct-05	574,297	2,051	83.3%	521,883	1,595	80.2%	1,096,180	52.4%	47.6%
Nov-05	526,880	2,162	80.2%	558,313	2,116	63.4%	1,085,193	48.6%	51.4%
Dec-05	614,590	2,154	81.1%	511,278	1,638	79.6%	1,125,868	54.6%	45.4%
Jan-06	590,135	2,168	81.0%	547,496	2,158	62.2%	1,137,630	51.9%	48.1%
Feb-06	546,738	2,192	82.0%	512,627	2,158	64.6%	1,059,365	51.6%	48.4%
Mar-06	640,072	2,173	80.0%	496,219	1,658	79.6%	1,136,291	56.3%	43.7%
Apr-06	549,733	2,097	81.9%	524,410	1,620	80.9%	1,074,143	51.2%	48.8%
May-06	582,975	2,068	80.1%	487,232	1,539	80.8%	1,070,207	54.5%	45.5%
Jun-06	564,298	2,042	78.5%	439,621	1,518	78.7%	1,003,920	56.2%	43.8%
Annual	6,889,314	2,192	77.6%	6,046,237	2,158	59.5%	12,935,551	53.3%	46.7%

Table 4 – On-Peak/Off-Peak Summary: Base Load

[1] Holidays included January 1, Martin Luther King Day, President's Day, Memorial Day, Fourth of July, Labor Day, Veteran's Day, Thanksgiving, Thanksgiving Friday, and Christmas Day.

Table 5 displays identical on-peak/off-peak information for the forecast year. The forecast percentages are very consistent with the base year percentages.

Forecast Year									
	On-Peak			Off-Peak			Summary		
Month	Monthly Use (MWh)	Max Demand (MW)	Load Factor (%)	Monthly Use (MWh)	Max Demand (MW)	Load Factor (%)	Total Monthly Use (MWh)	Percent On-Peak (%)	Percent Off-Peak (%)
July	493,615	2,075	74.3%	461,094	1,416	76.8%	954,709	51.7%	48.3%
August	569,804	2,072	74.7%	423,766	1,415	79.6%	993,570	57.3%	42.7%
September	531,900	2,012	78.7%	441,518	1,385	83.0%	973,418	54.6%	45.4%
October	547,279	1,996	81.6%	486,596	1,481	80.5%	1,033,875	52.9%	47.1%
November	508,253	2,122	78.8%	527,098	1,977	64.1%	1,035,351	49.1%	50.9%
December	593,604	2,120	79.5%	484,619	1,568	78.8%	1,078,223	55.1%	44.9%
January	576,823	2,118	81.1%	525,287	2,057	62.6%	1,102,110	52.3%	47.7%
February	532,436	2,127	82.3%	494,689	2,090	64.3%	1,027,125	51.8%	48.2%
March	620,207	2,099	80.3%	476,679	1,596	79.5%	1,096,886	56.5%	43.5%
April	525,711	2,071	79.3%	493,536	1,537	80.3%	1,019,247	51.6%	48.4%
May	533,133	2,049	73.9%	432,386	1,391	79.3%	965,520	55.2%	44.8%
June	542,362	2,035	75.7%	425,326	1,455	79.4%	967,688	56.0%	44.0%
Annual	6,575,127	2,127	76.4%	5,672,595	2,090	57.6%	12,247,723	53.7%	65.7%

Table 5 – On-Peak/Off-Peak Summary: Forecast Load

Energy Summary

Table 6 summarizes annual energy forecast results. Once again, the table presents the on-peak and off-peak energy use and percentages for the base case and, the forecast year. The base case on-peak energy use is calculated to be 6,889 GWh compared to a forecasted on-peak energy use of 6,575 GWh. This is a reduction of 314 GWh or 4.6%.

The base year off-peak energy use was 6,046 GWh compared to a forecasted energy use of 5,673 GWh. This is a reduction of 374 GWh or 6.2%.

	Energy Use (MWh)			Percentages (%)	
Description	On-Peak	Off-Peak	Total	On-Peak	Off-Peak
Base Case	6,889,314	6,046,237	12,935,551	53.3%	46.7%
Forecast Year	6,575,127	5,672,595	12,247,723	53.7%	46.3%
	Maximum Demand (MW)			Coincidence (%)	
Description	On-Peak	Off-Peak	Total	On-Peak	Off-Peak
Base Case	2,192	2,158	2,192	100.0%	98.4%
Forecast Year	2,127	2,090	2,127	100.0%	98.2%
	Load Factor (%)			Difference	
Description	On-Peak	Off-Peak	Total	On-Peak	Off-Peak
Base Case	76.4%	59.5%	67.4%		
Forecast Year	76.4%	57.6%	65.7%	0.0%	-1.9%

Table 6 – Annual Forecasts

Load Study Assumptions by Power Program

General Assumptions for All Power Programs:

- Base year hourly data for the period July 2005 through June 2006 was obtained from corporate records.
- When necessary, base year hourly loads were adjusted to "pre-curtailment" levels to compensate for known hydro curtailments.
- Corporate records used in the study included hydro curtailment information, SAP Business Warehouse records, Clark Energy Center Data Warehouse records, Wholesale Billing records and NYISO Billed Load data.
- Other information used in the development of the study included 10 year municipal and cooperative load forecasts prepared annually and load growth information contained in official Operating Forecasts.

II. Rural and Domestic

A) Firm:

- NIMO, NYSEG and RG&E contract demands totaled 301 MW for the base year in conformance with existing contracts.
- Based on billing records and dispatch schedules, hourly values were developed.
- Hourly data for the base year contained an annual load factor of 77% with monthly load factors ranging from 70% to 80%.
- 58 MW were reallocated to new re-licensing customers (see below section "New Re-Licensing Customers) and an additional 56 MW was withdrawn to deal with prior over-allocations resulting in a 187 MW contract demand for the forecast year.

B) Peaking:

- NIMO, NYSEG and RGE contract demands totaled 360 MW for the base year in conformance to existing contracts with no changes for the forecast year.
- Based on billing records and dispatch schedules hourly values were developed.
- Hourly data was reviewed and some inconsistencies with Power Contract provision were found and corrected.
- Generally hourly energy was at a 12.5% load factor with all energy taken in 4 to 5 weekday hours.

III. Replacement & Expansion Power

A) Expansion Power:

- NIMO, NYSEG and Jamestown contract demands reached the maximum allocation of 206 MW with 44 MW remaining unallocated in the base year.
- The base year monthly load factors ranging from 71% to 87%.
- The forecast year contract demand was increased to 250 MW with monthly load factors ranging from 71% to 87%.

B) Replacement Power:

- NIMO RP contract demand totaled 375 MW during the base year.
- 70 MW at 95 % load factor were allocated from use for the benefit of Energy Cost Savings Benefit customers back to RP in accordance with legislation, thus increasing the base year contract RP demand to 445 MW.
- For the forecast year RP was assumed to be marketed in a manner identical to EP with an annual load factor of 81% and monthly load factors ranging from 71% to 87%.

IV. Municipals & Coops.

- 14 full and 37 partial requirement customers have a contract demand allocation totaling 752 MW.
- During the base year individual customers utilized their full contract demand in different months and at different times during the day.
- Generally most customers utilized their full contract demand during the winter months of January, February, and March, while other customers experienced their maximum usage in the summer months of July, August and September.
- An annual load factor of 70% with a monthly range of 75% to 80% was achieved during the base year.
- At the date and time of the Niagara Project peak load the customers' contribution to peak was 702 MW for the base year.
- For the forecast year individual customer loads were assumed to grow independently of each other. All of the 752 MW of customer contract demand are projected to be utilized in the Niagara Project peak month.
- At the date and time of the Niagara Project peak load for the forecast year the customers' contribution to the peak is projected to be 713 MW.
- Load factors remain the same during the forecast year as for the base year.

V. Neighboring States

A) Firm

- The base year contract demand totaled 188 MW with annual load factor of 70% and monthly load factors ranging from 64% to 75%.
- No changes were made for the forecast year.

B) Peaking

- 5 Neighboring States Peaking customers are allocated 40 MW with maximum of 35 MW used during the base year.
- The 14% to 22% monthly load factor range was instituted in the base year.
- The forecast year contract demand was increased to 40 MW.
- The load shape was adjusted resulting in 12.5% annual and monthly load factors.

VI. New Re-licensing Customers

- 58 MW was reallocated from the block of power current sold to R&D customers to meet the obligations of the new re-licensing customers.
- The 58 MW total of the new re-licensing customers' allocation was distributed as follow:
    - 49 MW was assigned to seven governmental entities comprising the Host Communities under the Host Community Settlement Agreement. The Host Communities are: the City of Niagara Falls, Niagara County, the Towns of Lewiston and Niagara, and the school districts of Lewiston-Porter, Niagara-Wheatfield and the City of Niagara Falls.
    - 5 MW was allocated to Buffalo/Erie County, as part of a settlement with those entities on the re-licensing of the Niagara Power Project. 1 MW of Niagara power was allocated to the Tuscarora Nation.
    - 3 MW was assigned to Niagara University.

- 70% annual and monthly load factor was assumed for the future for the total new re-licensing customers' load.

Base Year

Month	Energy (mWh)	Weekday Coincident Peak Time	Coincident Peak (mW)	Average Peak Load (mW)	Load Factor
Jul-05	1,056,427	Mon Jul 25, 2005 3:00PM	2103	1420	68%
Aug-05	1,068,078	Thu Aug 4, 2005 2:00PM	2108	1436	68%
Sep-05	1,022,248	Tue Sep 13, 2005 3:00PM	2038	1420	70%
Oct-05	1,096,180	Tue Oct 25, 2005 2:00PM	2051	1473	72%
Nov-05	1,085,193	Thu Nov 17, 2005 7:00PM	2162	1507	70%
Dec-05	1,125,868	Wed Dec 14, 2005 7:00PM	2154	1513	70%
Jan-06	1,137,630	Thu Jan 26, 2006 7:00PM	2168	1529	71%
Feb-06	1,059,365	Mon Feb 27, 2006 7:00PM	2192	1576	72%
Mar-06	1,136,291	Fri Mar 3, 2006 8:00PM	2173	1527	70%
Apr-06	1,074,143	Wed Apr 5, 2006 11:00AM	2097	1492	71%
May-06	1,070,207	Wed May 31, 2006 2:00PM	2068	1438	70%
Jun-06	1,003,920	Thu Jun 22, 2006 5:00PM	2042	1394	68%
Annual	**12,935,551**	**Mon Feb 27, 2006 7:00PM**	**2192**	**1477**	**67%**

Base Year

Expansion Power					
Month	**Energy (mWh)**	**Weekday Non-Coincident Peak Time**	**Non-Coincident Peak (mW)**	**Average Peak Load (mW)**	**Load Factor**
Jul-05	106,538	Mon Jul 25, 2005 5:00PM	203	143	71%
Aug-05	116,999	Wed Aug 3, 2005 5:00PM	202	157	78%
Sep-05	110,497	Wed Sep 14, 2005 4:00PM	185	153	83%
Oct-05	115,252	Tue Oct 4, 2005 5:00PM	190	155	81%
Nov-05	107,206	Thu Nov 17, 2005 2:00PM	182	149	82%
Dec-05	110,205	Tue Dec 20, 2005 11:00AM	180	148	82%
Jan-06	104,975	Wed Jan 18, 2006 1:00PM	168	141	84%
Feb-06	106,652	Mon Feb 27, 2006 8:00PM	182	159	87%
Mar-06	117,265	Tue Mar 21, 2006 9:00PM	184	158	86%
Apr-06	116,243	Fri Apr 7, 2006 2:00PM	194	162	83%
May-06	108,943	Tue May 30, 2006 11:00PM	206	146	71%
Jun-06	111,431	Thu Jun 22, 2006 5:00PM	183	155	85%
Annual	**1,332,205**	**Tue May 30, 2006 11:00PM**	**206**	**152**	**74%**

Replacement Power					
Month	**Energy (mWh)**	**Weekday Non-Coincident Peak Time**	**Non-Coincident Peak (mW)**	**Average Peak Load (mW)**	**Load Factor**
Jul-05	314,526	Fri Jul 1, 2005 8:00AM	445	423	95%
Aug-05	314,526	Mon Aug 1, 2005 8:00AM	445	423	95%
Sep-05	304,380	Thu Sep 1, 2005 8:00AM	445	423	95%
Oct-05	314,950	Sat Oct 1, 2005 8:00AM	445	423	95%
Nov-05	304,381	Tue Nov 1, 2005 7:00AM	445	423	95%
Dec-05	314,527	Thu Dec 1, 2005 7:00AM	445	423	95%
Jan-06	314,527	Sun Jan 1, 2006 7:00AM	445	423	95%
Feb-06	284,089	Wed Feb 1, 2006 7:00AM	445	423	95%
Mar-06	314,525	Wed Mar 1, 2006 7:00AM	445	423	95%
Apr-06	303,961	Sun Apr 2, 2006 8:00AM	445	423	95%
May-06	314,527	Mon May 1, 2006 8:00AM	445	423	95%
Jun-06	304,381	Thu Jun 1, 2006 8:00AM	445	423	95%
Annual	**3,703,298**	**Fri Jul 1, 2005 8:00AM**	**445**	**423**	**95%**

Base Year

Rural and Domestic Firm					
Month	**Energy (mWh)**	**Weekday Non-Coincident Peak Time**	**Non-Coincident Peak (mW)**	**Average Peak Load (mW)**	**Load Factor**
Jul-05	166,784	Fri Jul 1, 2005 1:00AM	301	224.17	74%
Aug-05	162,647	Mon Aug 1, 2005 1:00AM	301	218.61	73%
Sep-05	163,493	Thu Sep 1, 2005 7:00AM	301	227.07	75%
Oct-05	177,797	Sat Oct 1, 2005 7:00AM	301	238.65	79%
Nov-05	166,603	Tue Nov 1, 2005 5:00AM	301	231.39	77%
Dec-05	171,060	Thu Dec 1, 2005 5:00AM	301	229.92	76%
Jan-06	172,408	Sun Jan 1, 2006 10:00AM	301	231.73	77%
Feb-06	164,603	Wed Feb 1, 2006 5:00AM	301	244.94	81%
Mar-06	172,850	Wed Mar 1, 2006 6:00AM	301	232.33	77%
Apr-06	171,812	Sat Apr 1, 2006 7:00AM	301	238.96	79%
May-06	176,512	Mon May 1, 2006 6:00AM	301	237.25	79%
Jun-06	152,614	Thu Jun 1, 2006 8:00AM	301	211.96	70%
Annual	**2,019,183**	**Fri Jul 1, 2005 1:00AM**	**301**	**231**	**77%**

Rural and Domestic Peaking					
Month	**Energy (mWh)**	**Weekday Non-Coincident Peak Time**	**Non-Coincident Peak (mW)**	**Average Peak Load (mW)**	**Load Factor**
Jul-05	33,480	Fri Jul 1, 2005 2:00PM	360	335	13%
Aug-05	33,488	Mon Aug 1, 2005 2:00PM	360	291	13%
Sep-05	32,403	Thu Sep 1, 2005 2:00PM	360	309	13%
Oct-05	33,474	Mon Oct 3, 2005 2:00PM	360	319	12%
Nov-05	34,020	Tue Nov 1, 2005 4:00PM	360	324	13%
Dec-05	33,484	Thu Dec 1, 2005 4:00PM	360	304	13%
Jan-06	33,484	Mon Jan 2, 2006 4:00PM	360	304	13%
Feb-06	30,240	Wed Feb 1, 2006 5:00PM	360	302	13%
Mar-06	33,488	Wed Mar 1, 2006 8:00AM	360	291	13%
Apr-06	32,400	Mon Apr 3, 2006 11:00AM	360	324	13%
May-06	33,484	Mon May 1, 2006 11:00AM	360	304	13%
Jun-06	32,406	Thu Jun 1, 2006 2:00PM	360	295	13%
Annual	**395,851**	**Fri Jul 1, 2005 2:00PM**	**360**	**308**	**13%**

Base Year

Neighboring States Firm					
Month	**Energy (mWh)**	**Weekday Non-Coincident Peak Time**	**Non-Coincident Peak (mW)**	**Average Peak Load (mW)**	**Load Factor**
Jul-05	92,228	Mon Jul 11, 2005 12:00PM	182	124	68%
Aug-05	91,694	Thu Aug 4, 2005 2:00PM	188	123	66%
Sep-05	86,084	Tue Sep 13, 2005 3:00PM	183	120	65%
Oct-05	95,581	Tue Oct 4, 2005 7:00PM	188	128	68%
Nov-05	98,200	Thu Nov 10, 2005 5:00PM	187	136	73%
Dec-05	104,722	Thu Dec 1, 2005 5:00PM	188	141	75%
Jan-06	105,262	Mon Jan 9, 2006 6:00PM	188	141	75%
Feb-06	92,617	Mon Feb 6, 2006 6:00PM	188	138	73%
Mar-06	99,451	Mon Mar 6, 2006 7:00PM	186	134	72%
Apr-06	94,818	Wed Apr 26, 2006 9:00PM	186	132	71%
May-06	97,430	Wed May 3, 2006 2:00PM	184	131	71%
Jun-06	85,780	Mon Jun 26, 2006 5:00PM	186	119	64%
Annual	**1,143,867**	**Thu Aug 4, 2005 2:00PM**	**188**	**131**	**69%**

Neighboring States Peaking					
Month	**Energy (mWh)**	**Weekday Non-Coincident Peak Time**	**Non-Coincident Peak (mW)**	**Average Peak Load (mW)**	**Load Factor**
Jul-05	3,719	Wed Jul 13, 2005 3:00PM	30	9	17%
Aug-05	3,719	Tue Aug 9, 2005 4:00PM	33	7	15%
Sep-05	3,600	Thu Sep 15, 2005 8:00PM	24	8	21%
Oct-05	3,725	Wed Oct 5, 2005 8:00PM	33	8	15%
Nov-05	3,601	Mon Nov 7, 2005 5:00PM	35	8	14%
Dec-05	3,718	Tue Dec 13, 2005 6:00PM	35	8	14%
Jan-06	3,721	Wed Jan 25, 2006 6:00PM	33	8	15%
Feb-06	3,359	Wed Feb 1, 2006 6:00PM	34	8	15%
Mar-06	3,718	Tue Mar 21, 2006 7:00PM	34	8	15%
Apr-06	3,596	Fri Apr 14, 2006 9:00PM	30	9	17%
May-06	3,719	Thu May 4, 2006 1:00PM	23	8	22%
Jun-06	3,601	Mon Jun 12, 2006 5:00PM	34	8	15%
Annual	**43,796**	**Mon Nov 7, 2005 5:00PM**	**35**	**8**	**23%**

Base Year

Municipals and Coops.					
Month	**Energy (mWh)**	**Weekday Non-Coincident Peak Time**	**Non-Coincident Peak (mW)**	**Average Peak Load (mW)**	**Load Factor**
Jul-05	339,152	Mon Jul 18, 2005 2:00PM	596	456	76%
Aug-05	345,004	Wed Aug 10, 2005 2:00PM	608	464	76%
Sep-05	321,791	Tue Sep 13, 2005 2:00PM	558	447	80%
Oct-05	356,539	Thu Oct 27, 2005 10:00AM	627	479	76%
Nov-05	371,201	Wed Nov 23, 2005 6:00PM	676	516	76%
Dec-05	388,304	Wed Dec 14, 2005 7:00PM	667	522	78%
Jan-06	403,273	Mon Jan 16, 2006 7:00PM	690	542	79%
Feb-06	377,716	Mon Feb 27, 2006 8:00AM	702	562	80%
Mar-06	394,978	Wed Mar 1, 2006 8:00AM	682	531	78%
Apr-06	350,096	Thu Apr 6, 2006 9:00AM	648	487	75%
May-06	335,593	Mon May 22, 2006 9:00AM	581	451	78%
Jun-06	313,708	Mon Jun 19, 2006 12:00PM	552	436	79%
Annual	**4,297,355**	**Mon Feb 27, 2006 8:00AM**	**702**	**491**	**70%**

Forecast Year

Month	Energy (mWh)	Weekday Coincident Peak Time	Coincident Peak (mW)	Average Peak Load (mW)	Load Factor
July	954,709	4PM	2075	1283	62%
August	993,570	2PM	2072	1335	64%
September	973,418	5PM	2012	1352	67%
October	1,033,875	2PM	1996	1390	70%
November	1,035,351	7PM	2122	1438	68%
December	1,078,223	7PM	2120	1449	68%
January	1,102,110	5PM	2118	1481	70%
February	1,027,125	9PM	2127	1528	72%
March	1,096,886	9PM	2099	1474	70%
April	1,019,247	2PM	2071	1416	68%
May	965,520	2PM	2049	1298	63%
June	967,688	5PM	2035	1344	66%
Annual	**12,247,723**	**9PM**	**2127**	**1398**	**66%**

Forecast Year

Expansion Power					
Month	**Energy (mWh)**	**Weekday Non-Coincident Peak Time**	**Non-Coincident Peak (mW)**	**Average Peak Load (mW)**	**Load Factor**
July	124,828	5:00 PM	237	168	71%
August	137,653	5:00PM	238	185	78%
September	141,472	4:00PM	237	196	83%
October	143,697	5:00PM	237	193	81%
November	140,054	2:00PM	237	195	82%
December	145,743	11:00AM	238	196	82%
January	148,437	1:00PM	237	200	84%
February	139,333	8:00PM	238	207	87%
March	151,435	9:00PM	238	204	86%
April	142,279	2:00PM	238	198	83%
May	125,843	11:00PM	238	169	71%
June	144,905	5:00PM	238	201	85%
Annual	**1,685,680**	**5:00PM**	**238**	**192**	**81%**

Replacement Power					
Month	**Energy (mWh)**	**Weekday Non-Coincident Peak Time**	**Non-Coincident Peak (mW)**	**Average Peak Load (mW)**	**Load Factor**
July	222,194	5:00 PM	423	299	71%
August	245,022	5:00PM	423	329	78%
September	251,820	4:00PM	423	350	83%
October	255,780	5:00PM	423	343	81%
November	249,297	2:00PM	423	346	82%
December	259,422	11:00AM	423	349	82%
January	264,218	1:00PM	423	355	84%
February	248,013	8:00PM	423	369	87%
March	269,554	9:00PM	423	362	86%
April	253,257	2:00PM	423	352	83%
May	224,000	11:00PM	423	301	71%
June	257,931	5:00PM	423	358	85%
Annual	**3,000,510**	**5:00PM**	**423**	**343**	**81%**

Forecast Year

Rural and Domestic Firm					
Month	**Energy (mWh)**	**Weekday Non-Coincident Peak Time**	**Non-Coincident Peak (mW)**	**Average Peak Load (mW)**	**Load Factor**
July	103,617	7:00AM	187	139	74%
August	101,048	7:00AM	187	136	73%
September	101,572	7:00AM	187	141	75%
October	110,459	7:00AM	187	148	79%
November	103,504	6:00AM	187	144	77%
December	106,274	8:00AM	187	143	76%
January	107,111	11:00AM	187	144	77%
February	102,257	6:00AM	187	152	81%
March	107,385	6:00AM	187	144	77%
April	106,741	6:00AM	187	148	79%
May	109,661	9:00AM	187	147	79%
June	94,813	9:00AM	187	132	70%
Annual	**1,254,440**	**9:00AM**	**187**	**143**	**77%**

Rural and Domestic Peaking					
Month	**Energy (mWh)**	**Weekday Non-Coincident Peak Time**	**Non-Coincident Peak (mW)**	**Average Peak Load (mW)**	**Load Factor**
July	33,480	2:00PM	360	335	13%
August	33,488	2:00PM	360	291	13%
September	32,403	2:00PM	360	309	13%
October	33,474	2:00PM	360	319	12%
November	34,020	4:00PM	360	324	13%
December	33,484	4:00PM	360	304	13%
January	33,484	4:00PM	360	304	13%
February	30,240	5:00PM	360	302	13%
March	33,488	8:00AM	360	291	13%
April	32,400	11:00AM	360	324	13%
May	33,484	11:00AM	360	304	13%
June	32,406	2:00PM	360	295	13%
Annual	**395,851**	**2:00PM**	**360**	**308**	**13%**

Forecast Year

Neighboring States Firm					
Month	**Energy (mWh)**	**Weekday Non-Coincident Peak Time**	**Non-Coincident Peak (mW)**	**Average Peak Load (mW)**	**Load Factor**
July	92,228	12:00PM	182	124	68%
August	91,694	2:00PM	188	123	66%
September	86,084	3:00PM	183	120	65%
October	95,581	7:00PM	188	128	68%
November	98,200	5:00PM	187	136	73%
December	104,722	5:00PM	188	141	75%
January	105,262	6:00PM	188	141	75%
February	92,617	6:00PM	188	138	73%
March	99,451	7:00PM	186	134	72%
April	94,818	9:00PM	186	132	71%
May	97,430	2:00PM	184	131	71%
June	85,780	5:00PM	186	119	64%
Annual	**1,143,867**	**2:00PM**	**188**	**131**	**69%**

Neighboring States Peaking					
Month	**Energy (mWh)**	**Weekday Non-Coincident Peak Time**	**Non-Coincident Peak (mW)**	**Average Peak Load (mW)**	**Load Factor**
July	3,650	2:00PM	40	37	12%
August	3,650	2:00PM	40	40	12%
September	3,650	5:00PM	40	35	13%
October	3,650	5:00PM	40	35	12%
November	3,650	4:00PM	40	37	13%
December	3,650	4:00PM	40	35	12%
January	3,650	2:00PM	40	33	12%
February	3,650	12:00PM	40	37	14%
March	3,650	1:00PM	40	40	12%
April	3,650	1:00PM	40	37	13%
May	3,650	2:00PM	40	40	12%
June	3,650	3:00PM	40	33	13%
Annual	**43,800**	**2:00PM**	**40**	**36**	**13%**

Forecast Year

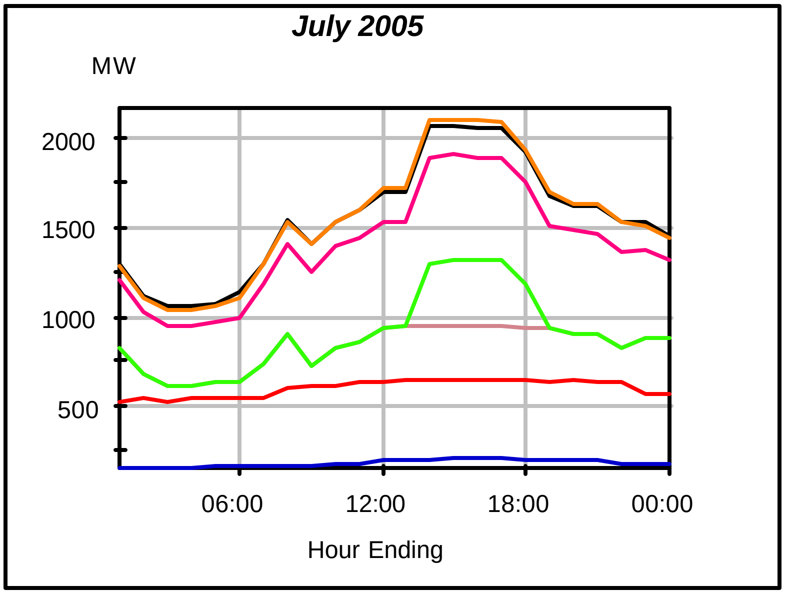
Municipals and Coops.					
Month	**Energy (mWh)**	**Weekday Non-Coincident Peak Time**	**Non-Coincident Peak (mW)**	**Average Peak Load (mW)**	**Load Factor**
July	344,652	2:00PM	606	463	76%
August	350,598	2:00PM	618	471	76%
September	327,010	2:00PM	567	454	80%
October	362,321	10:00AM	637	486	76%
November	377,220	6:00PM	687	524	76%
December	394,601	7:00PM	678	530	78%
January	409,813	7:00PM	701	551	79%
February	383,841	8:00AM	713	571	80%
March	401,383	8:00AM	693	539	78%
April	355,773	9:00AM	659	495	75%
May	341,035	9:00AM	590	458	78%
June	318,795	12:00PM	561	443	79%
Annual	**4,367,042**	**8:00AM**	**713**	**499**	**70%**

Forecast Year

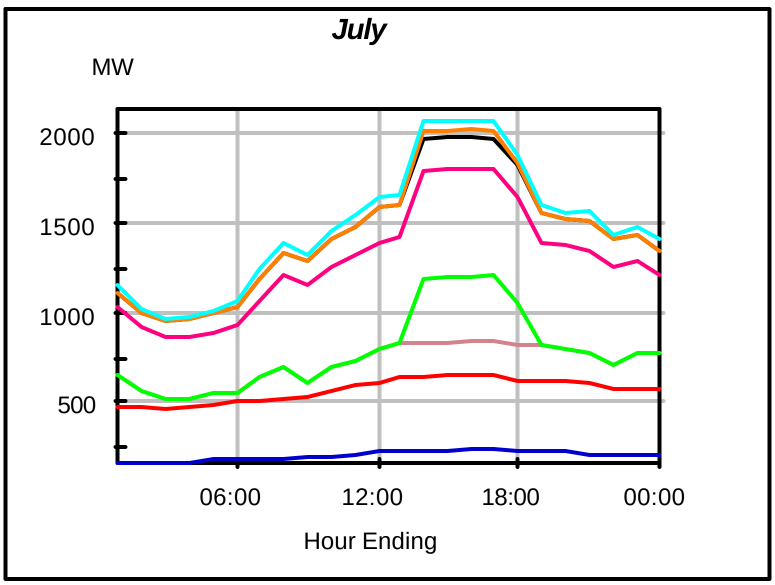
New Re-licensing Customers					
Month	**Energy (mWh)**	**Weekday Non-Coincident Peak Time**	**Non-Coincident Peak (mW)**	**Average Peak Load (mW)**	**Load Factor**
July	30,060	8:00AM	58	40	70%
August	30,416	8:00AM	58	41	70%
September	29,407	8:00AM	58	41	70%
October	30,071	1:00AM	58	40	70%
November	29,407	7:00AM	58	41	70%
December	30,355	7:00AM	58	41	70%
January	30,261	7:00AM	58	41	70%
February	27,131	7:00AM	58	40	70%
March	30,443	7:00AM	58	41	70%
April	29,156	7:00AM	58	41	70%
May	30,416	8:00AM	58	41	70%
June	29,407	8:00AM	58	41	70%
Annual	**356,530**	**8:00AM**	**58**	**41**	**70%**

Peak Day

Base Year



Forecast Year



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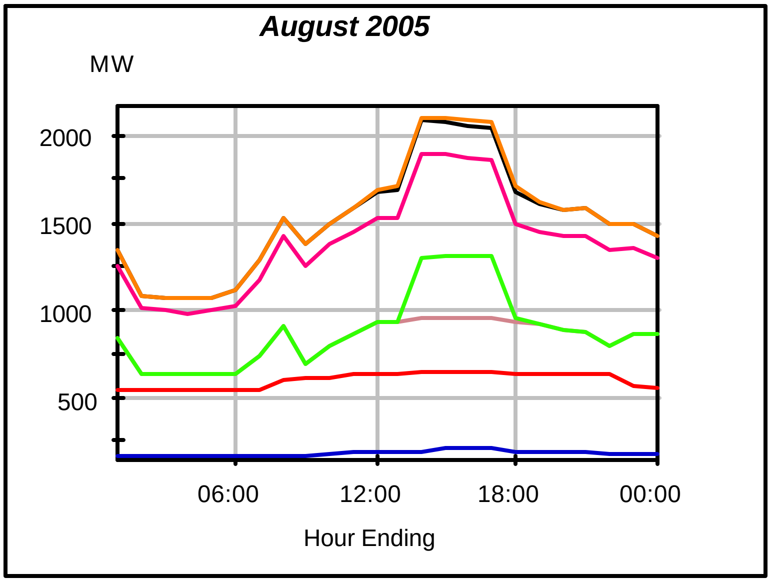
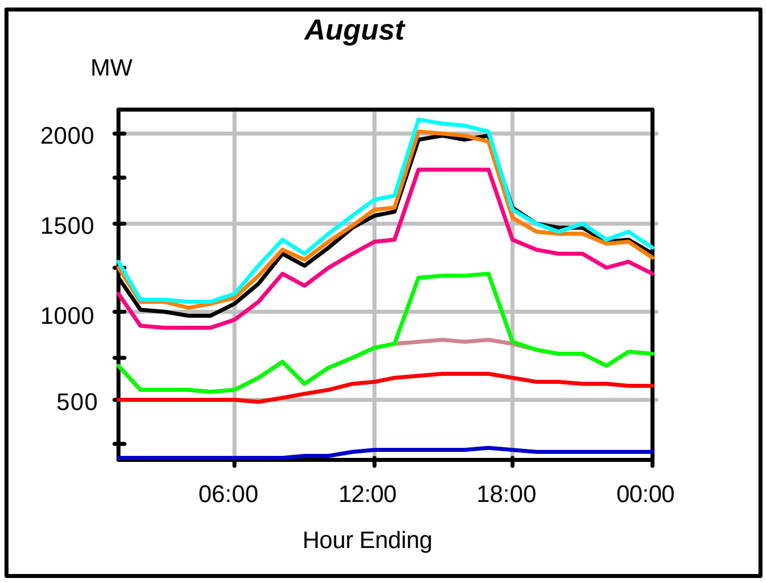
Peak Day

Base Year



Forecast Year



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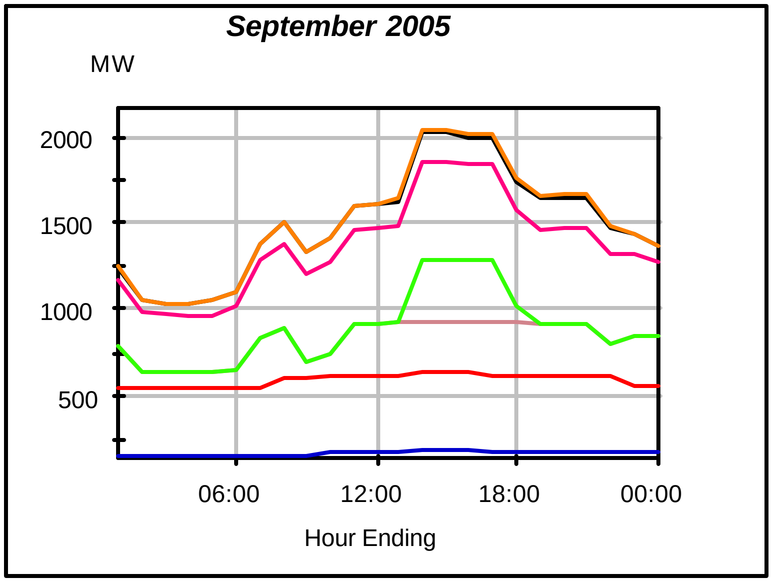

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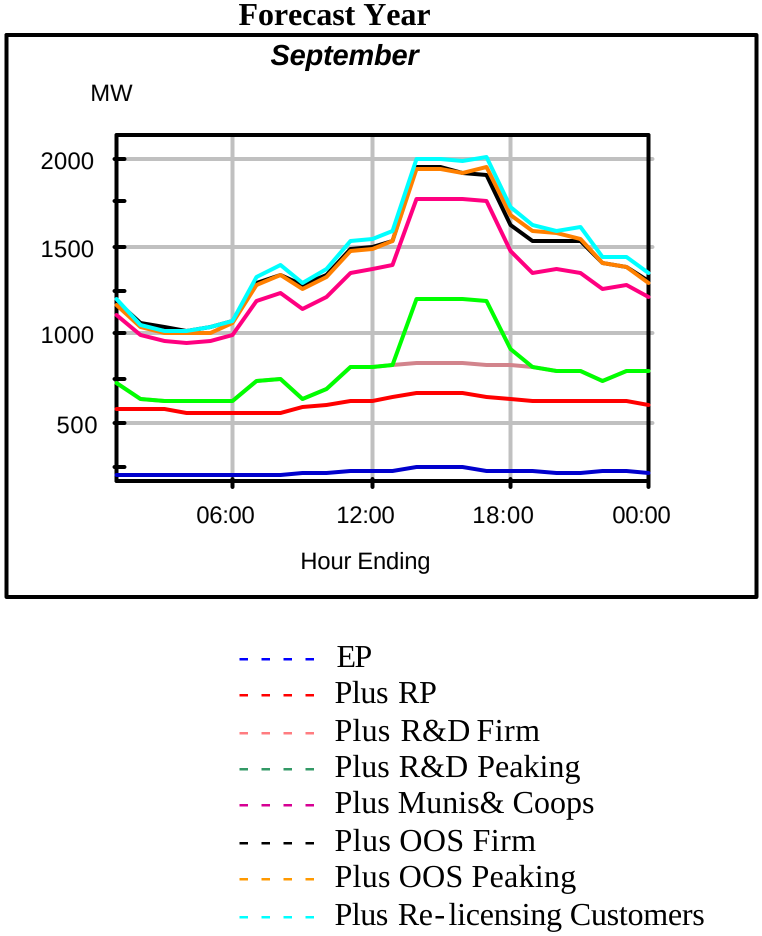

Peak Day

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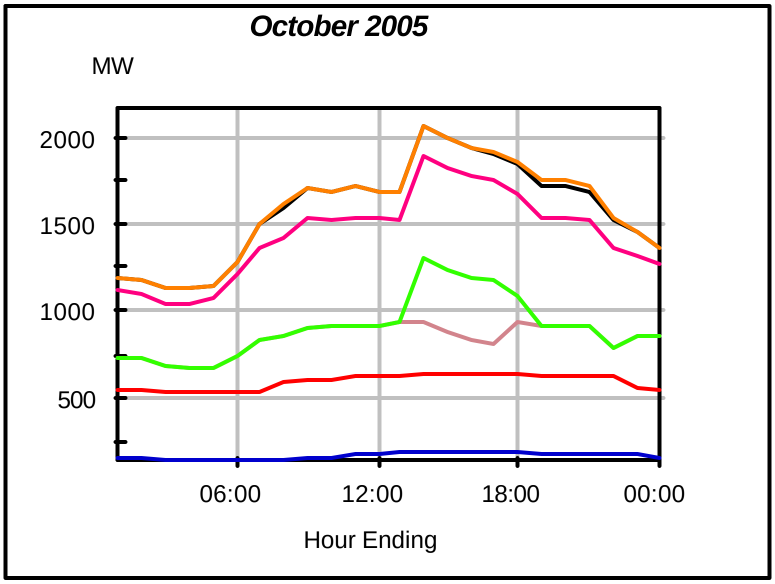

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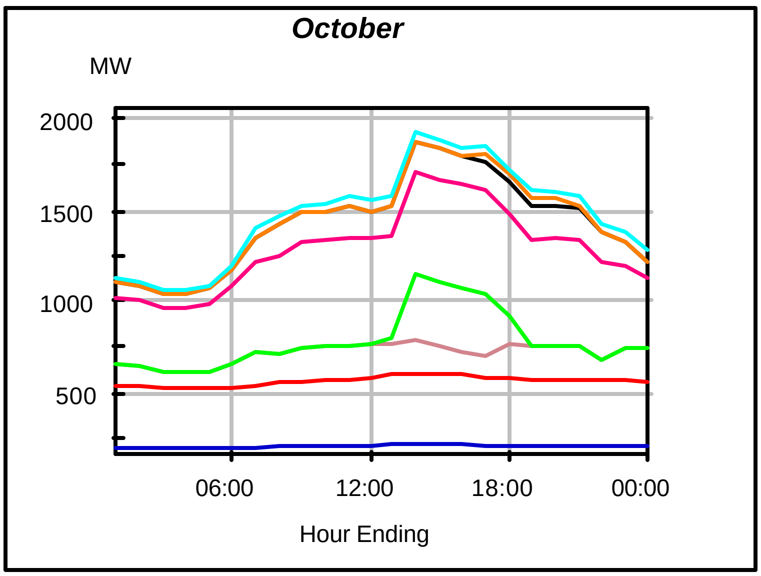

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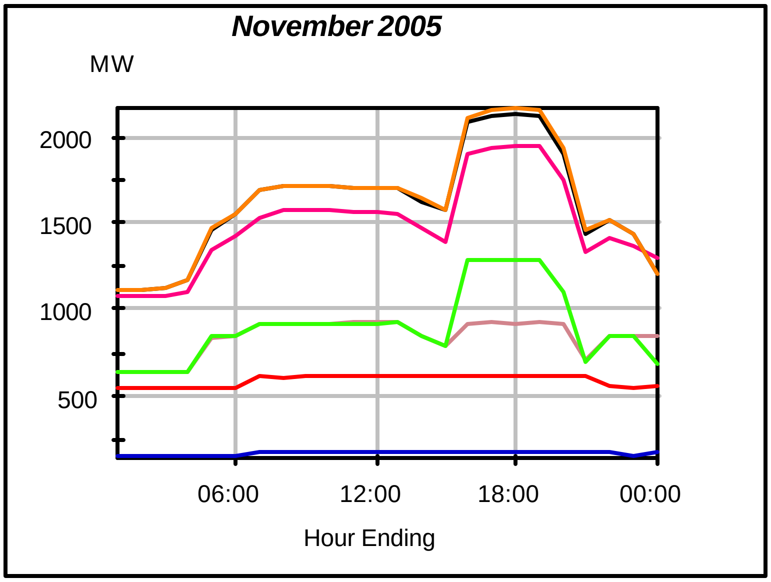

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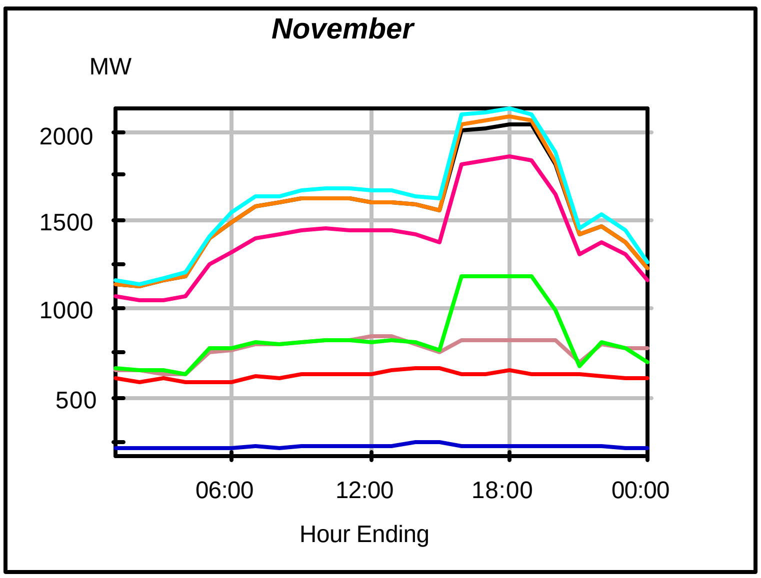

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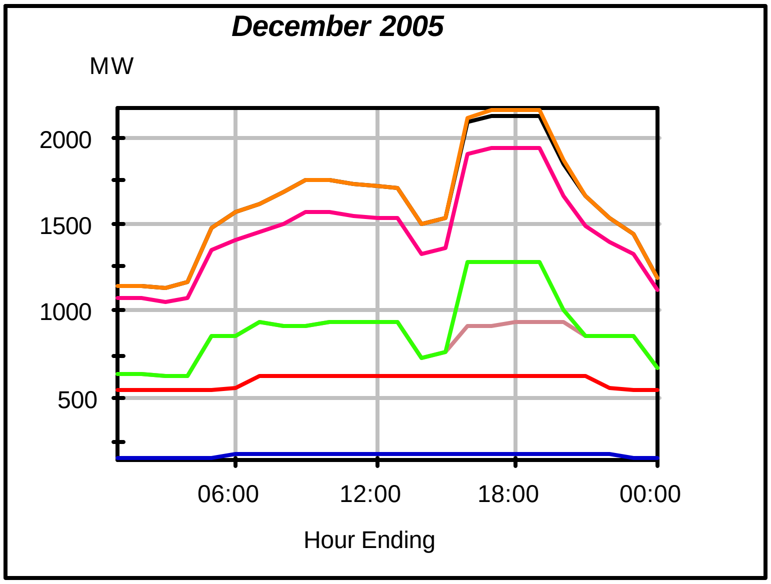

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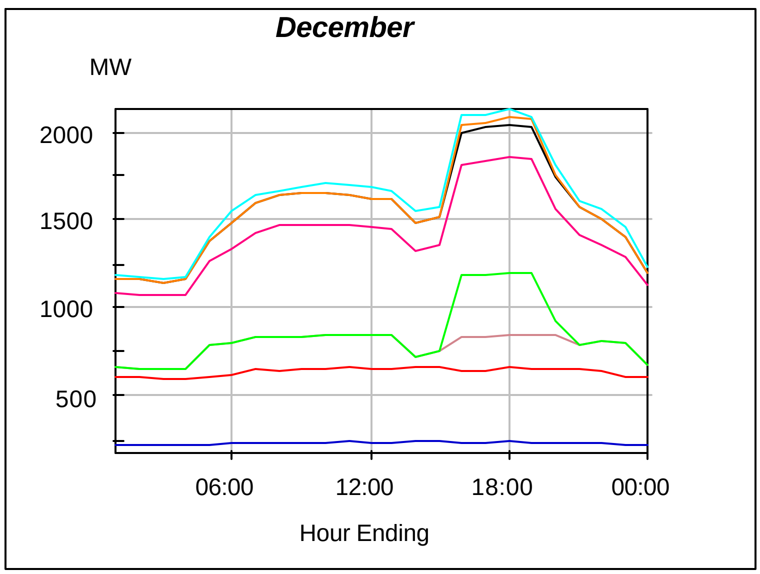

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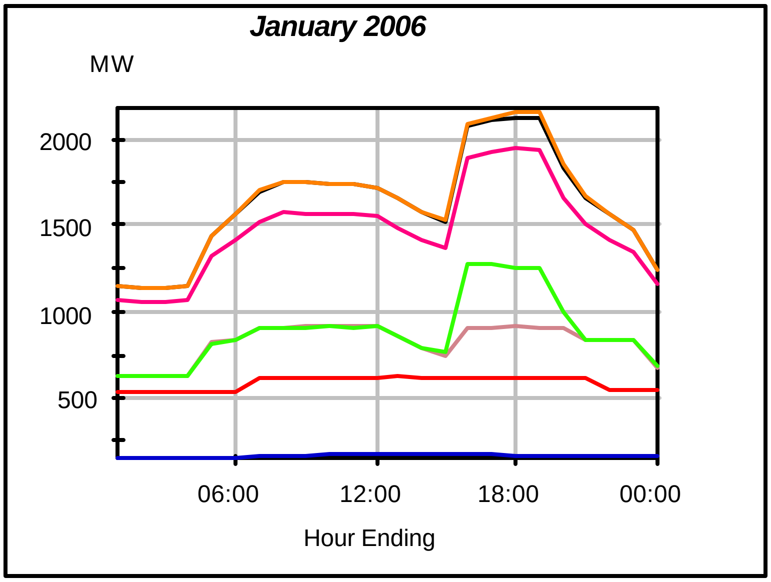

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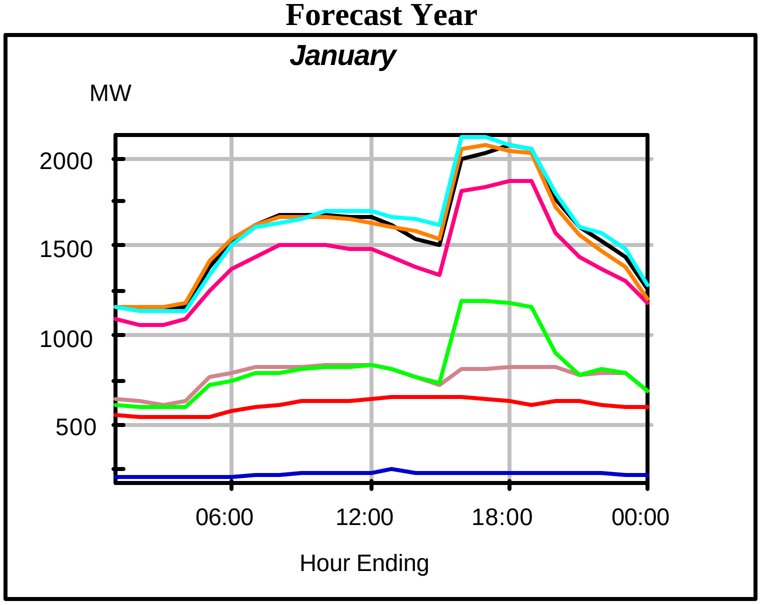

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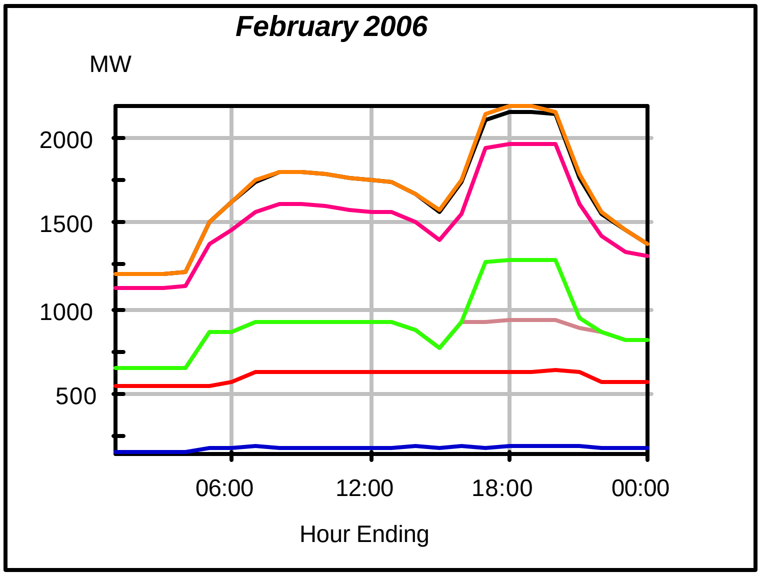

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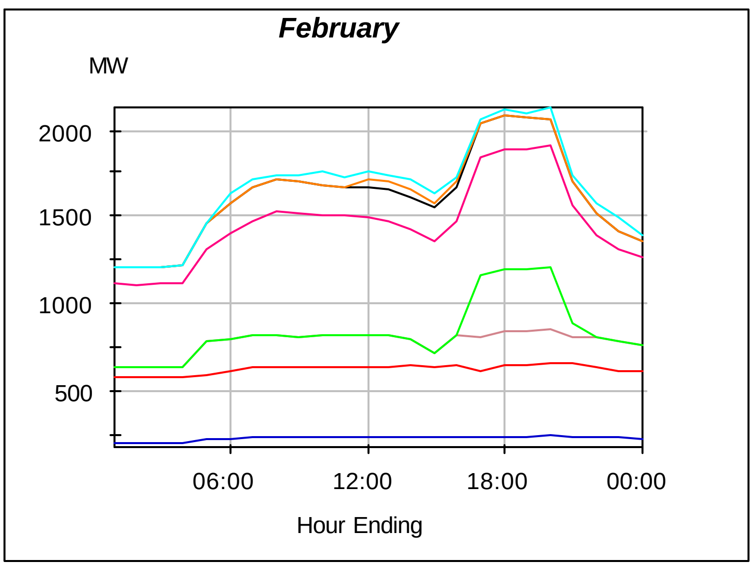

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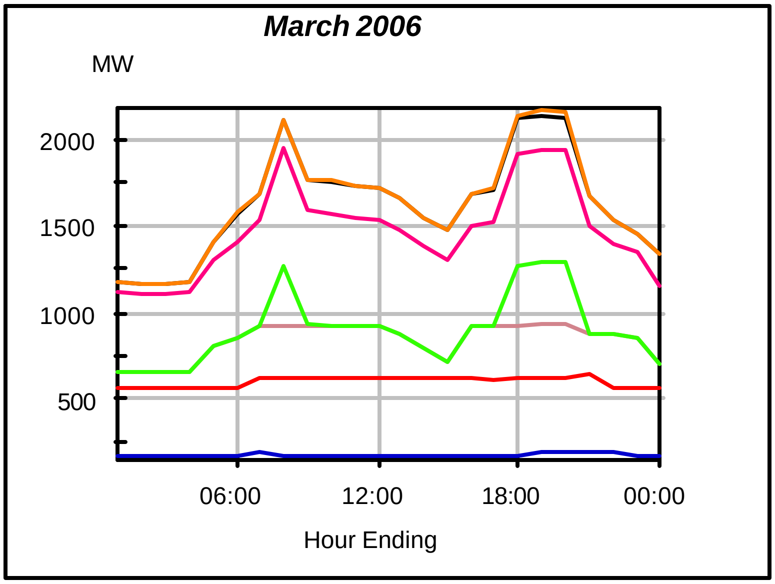

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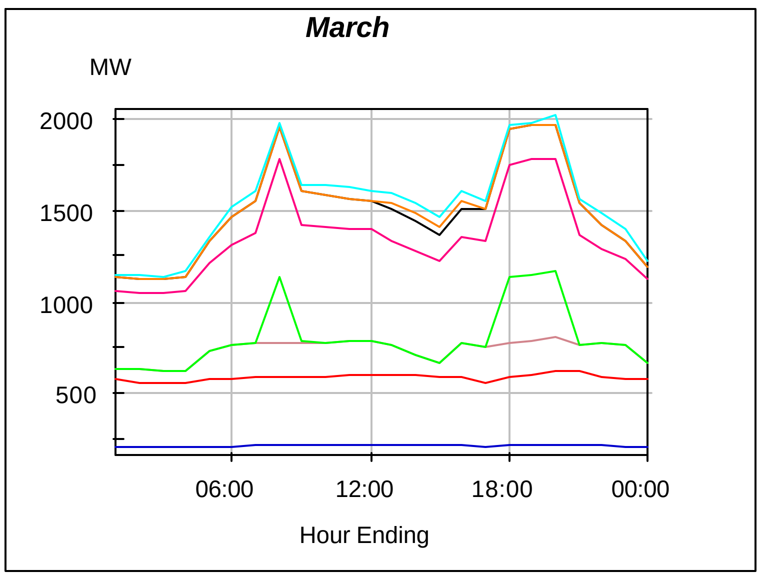

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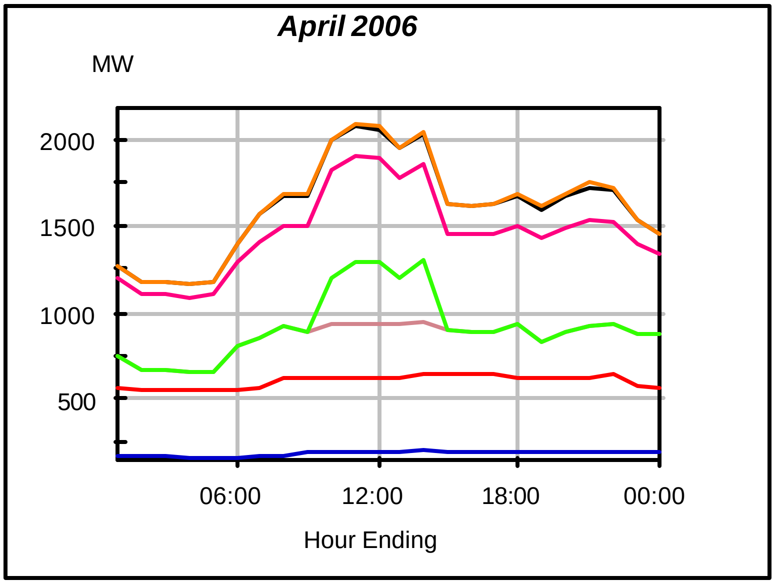

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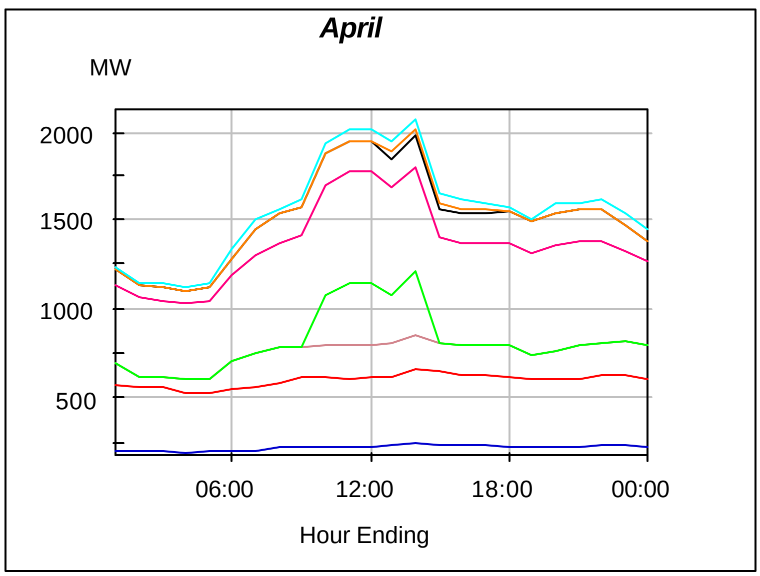

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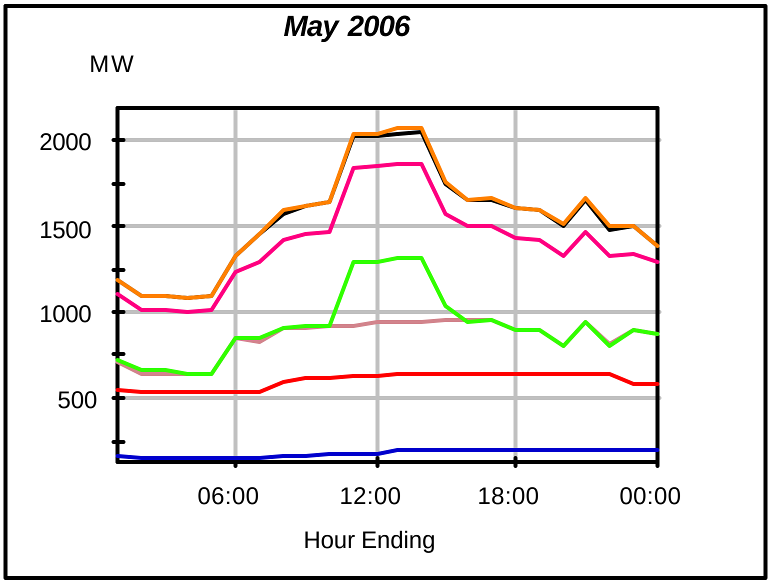

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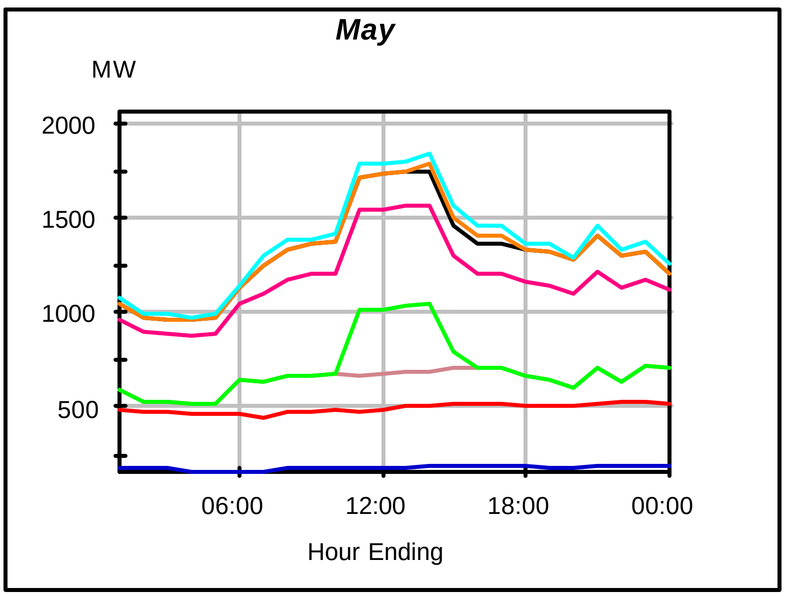

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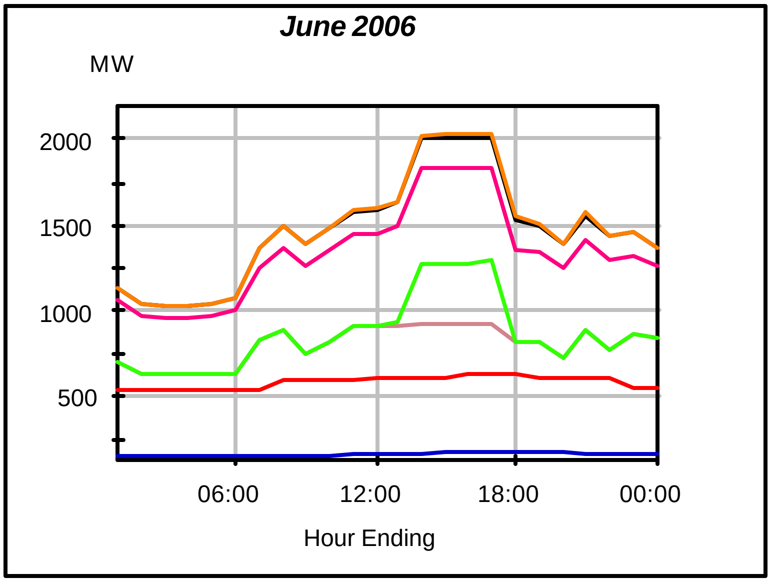

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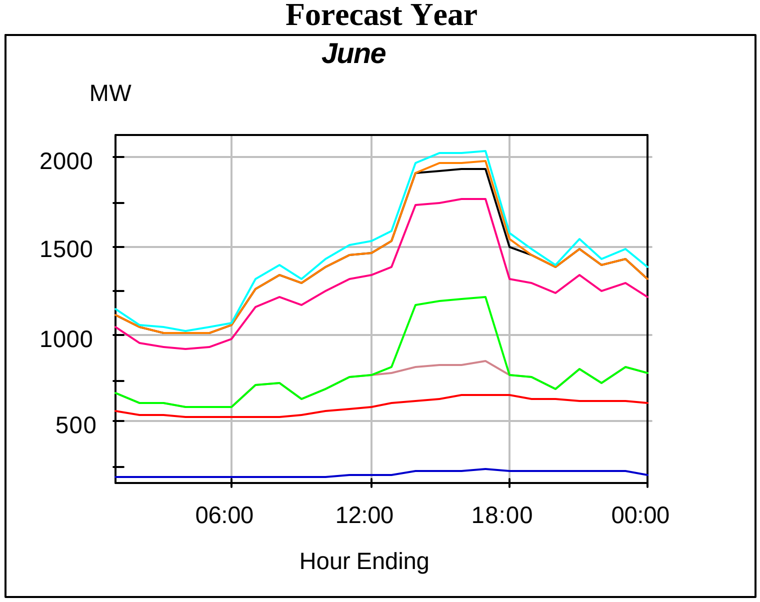

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Average Weekday

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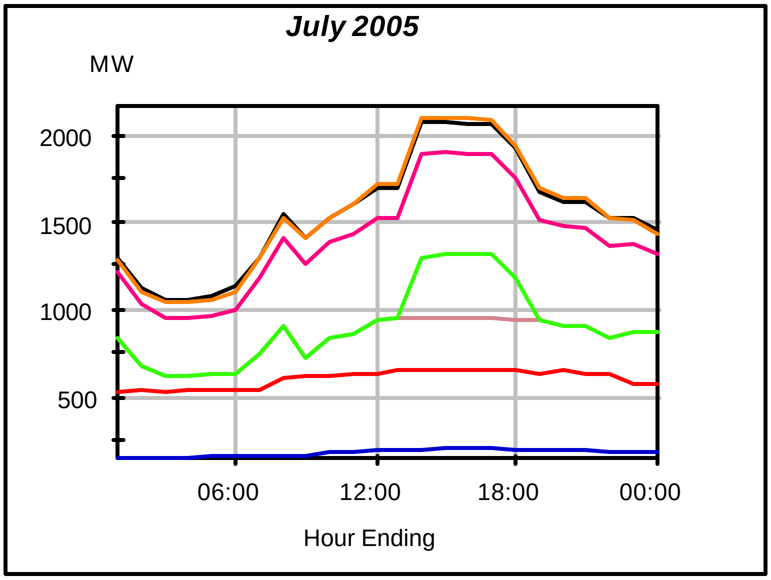

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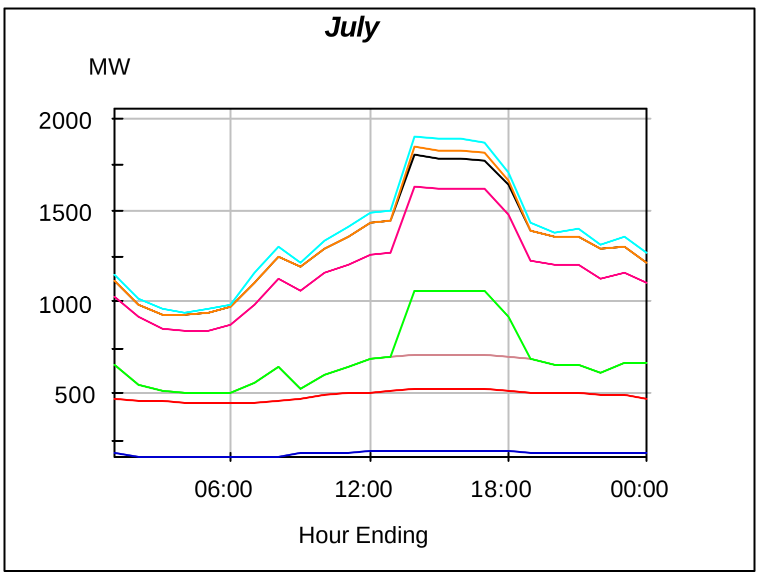

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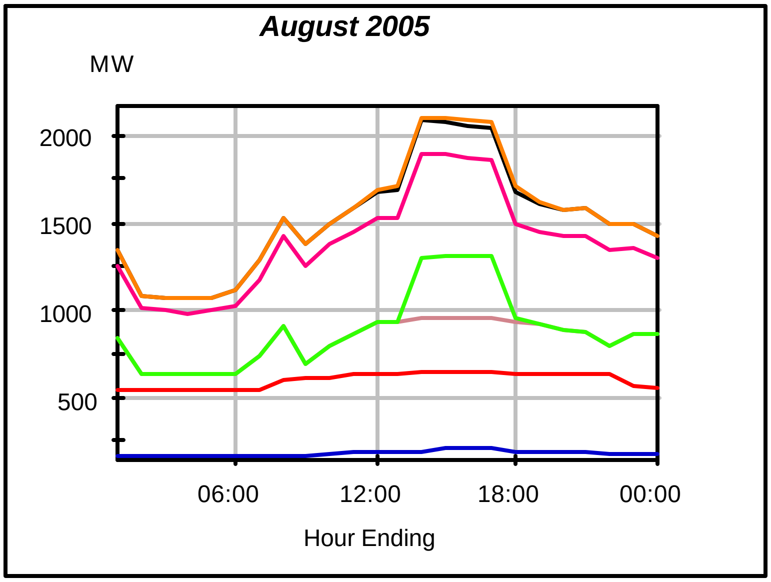

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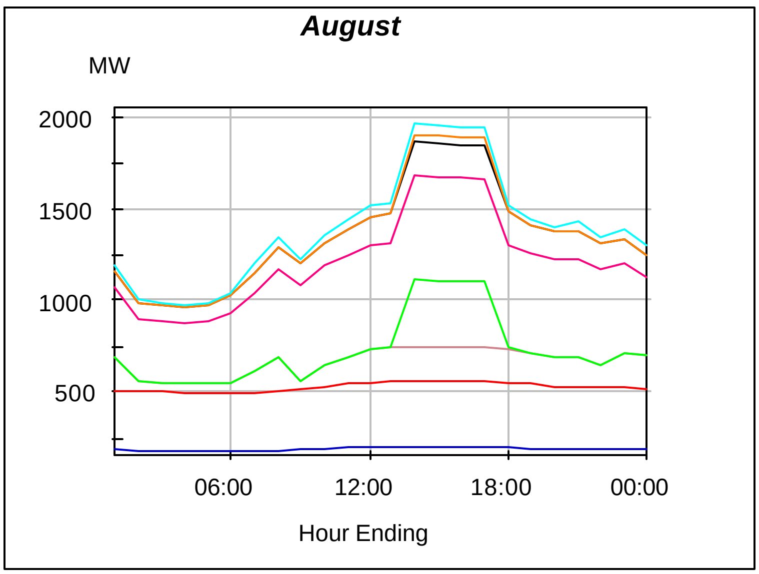

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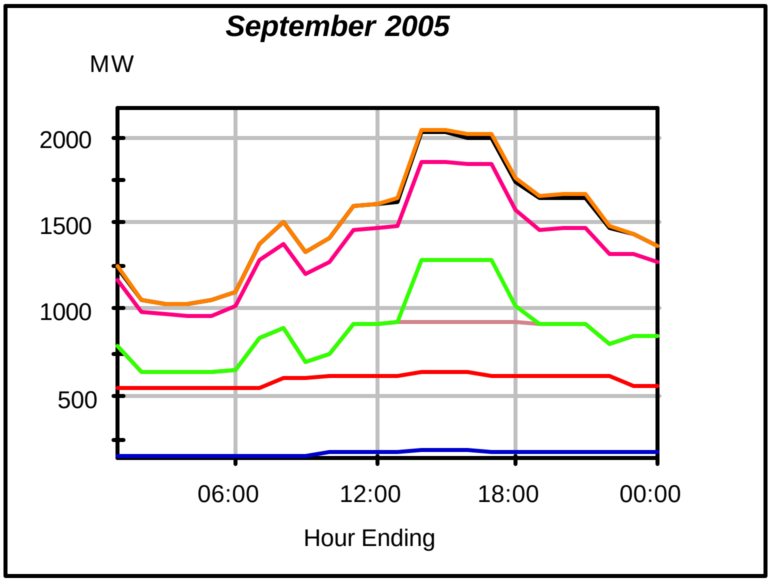

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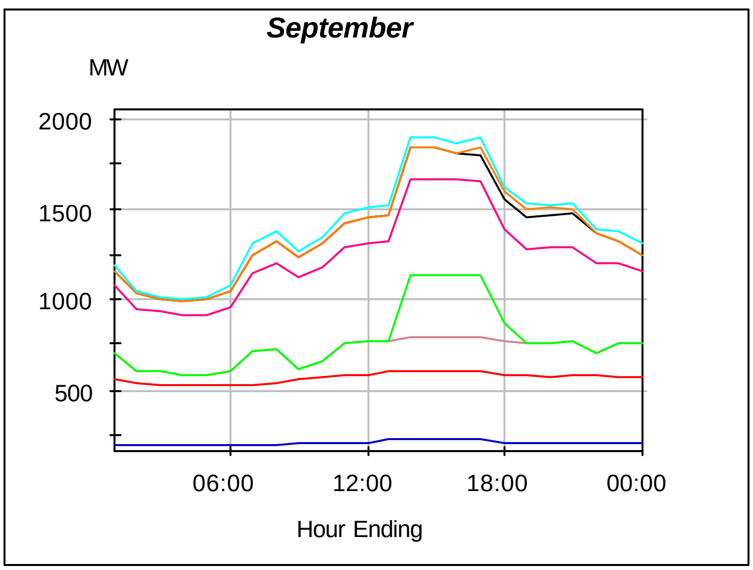

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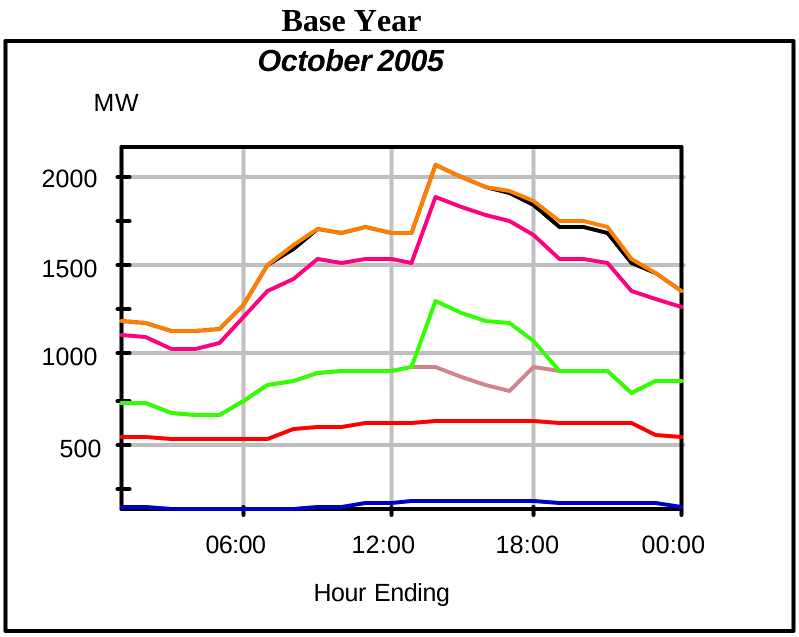

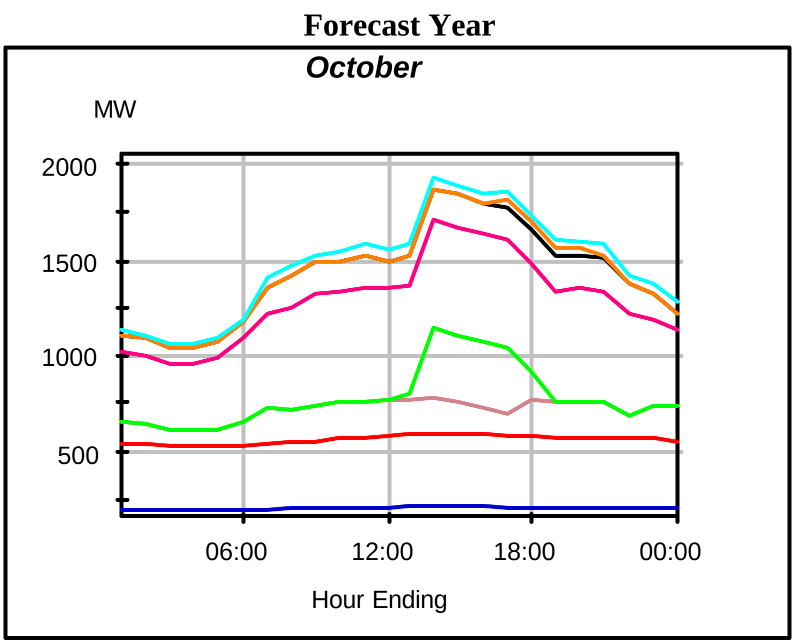

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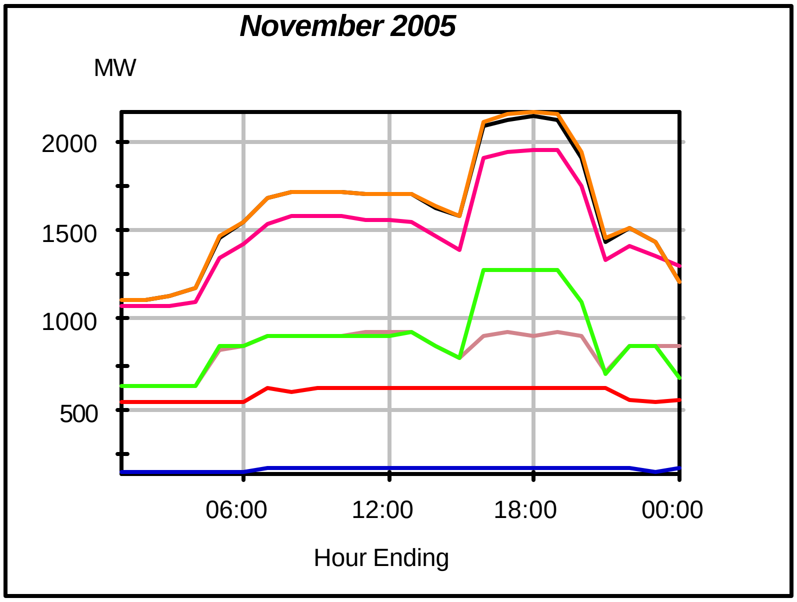
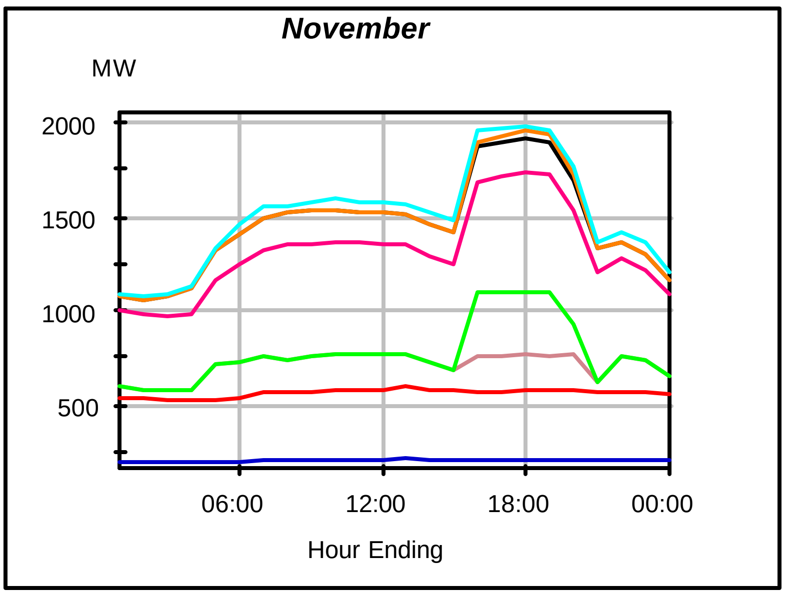


Forecast Year



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Average Weekday

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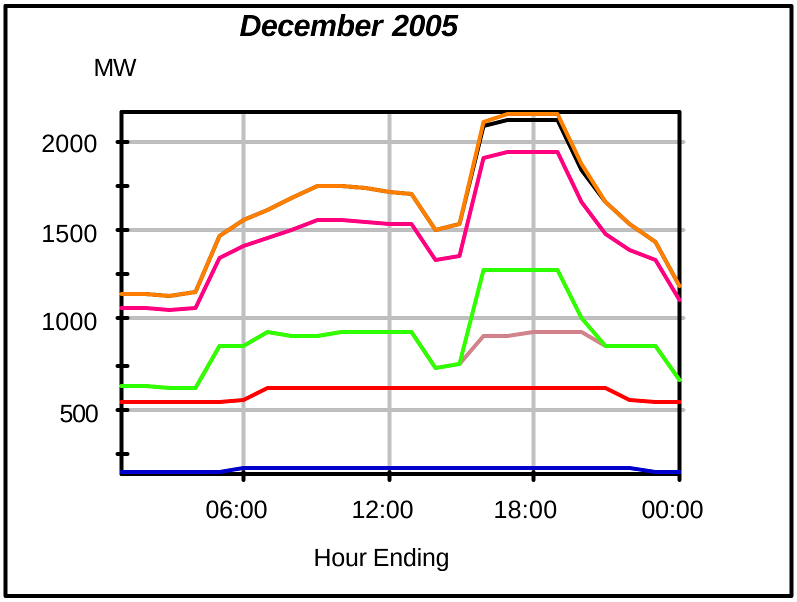

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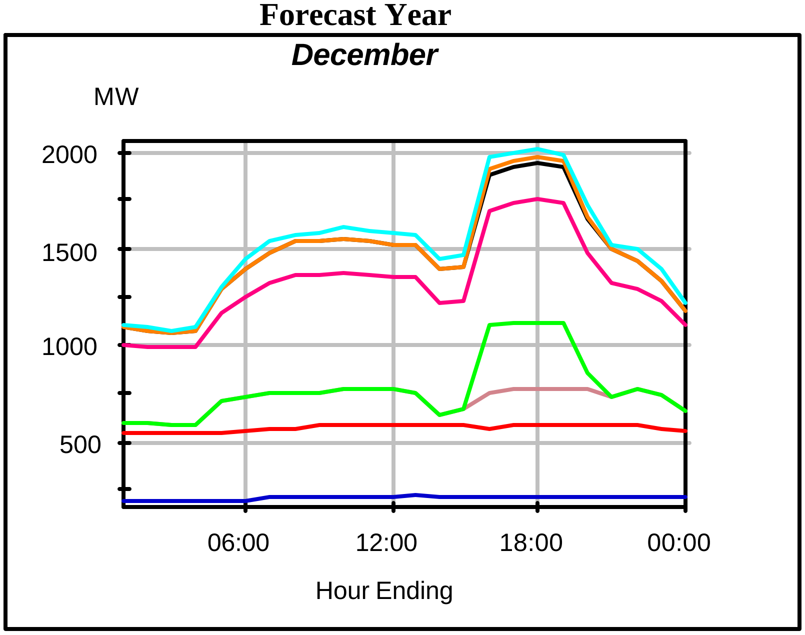

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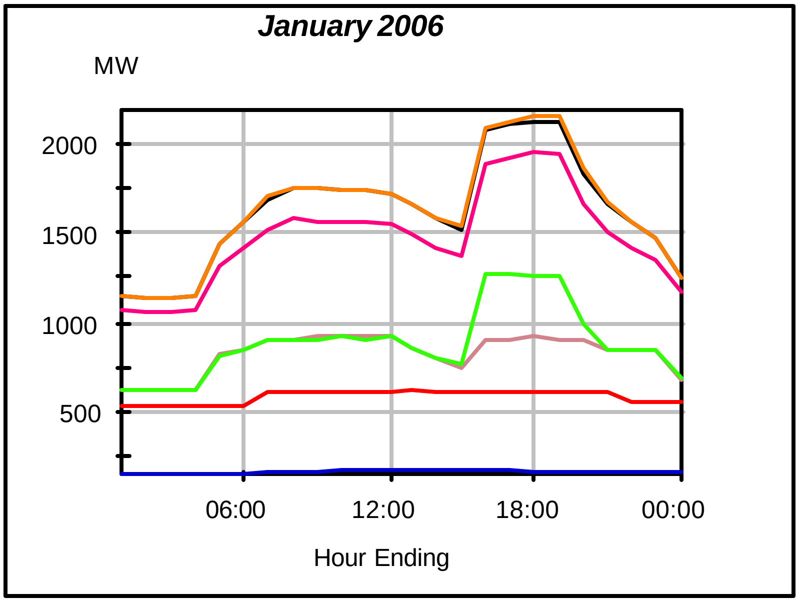

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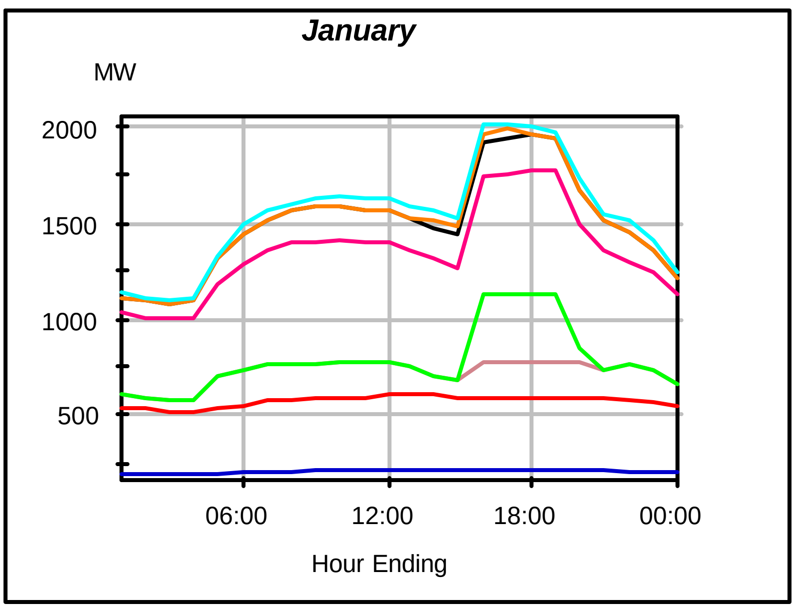

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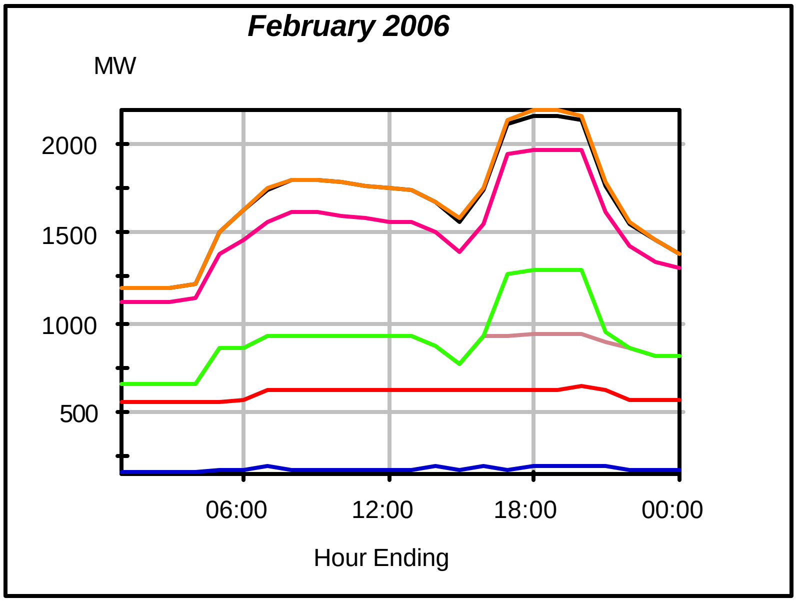

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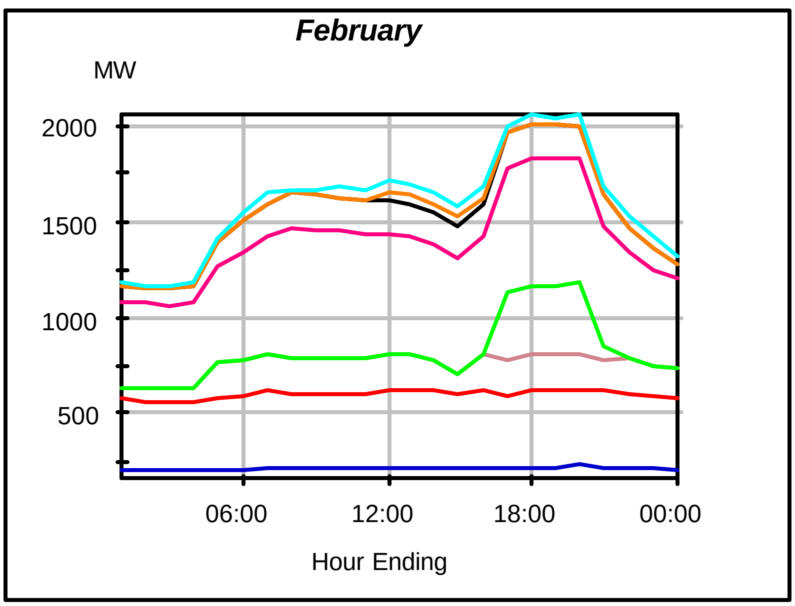

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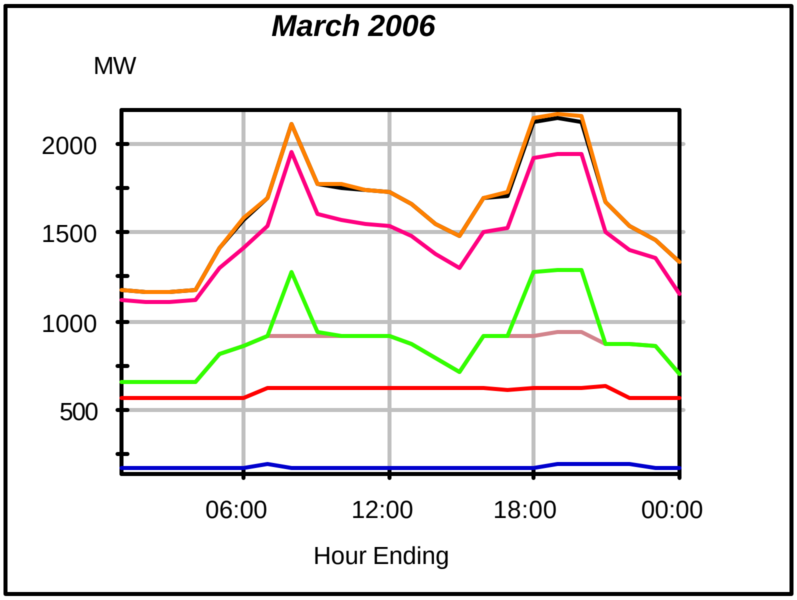

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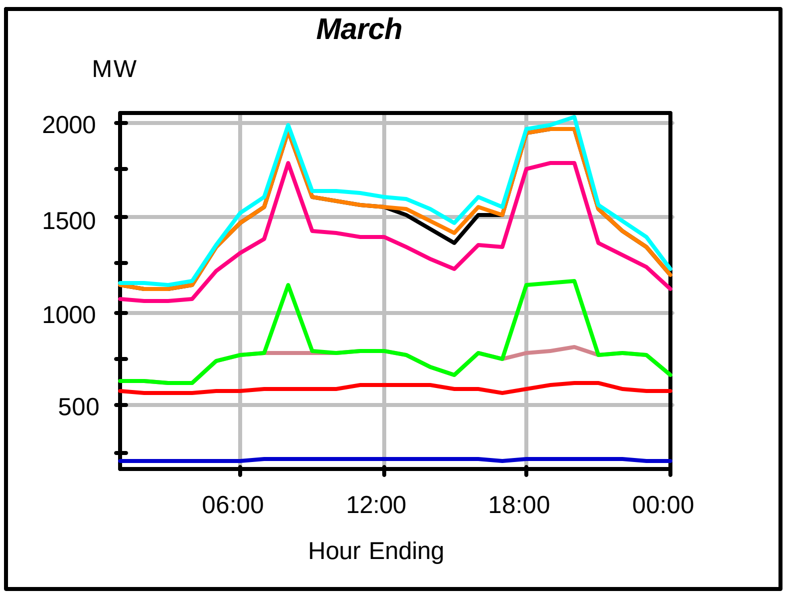

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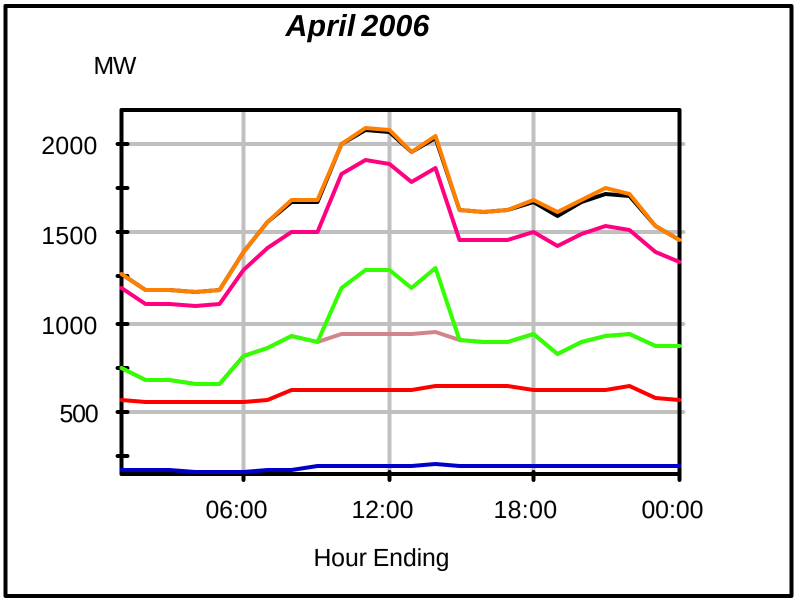
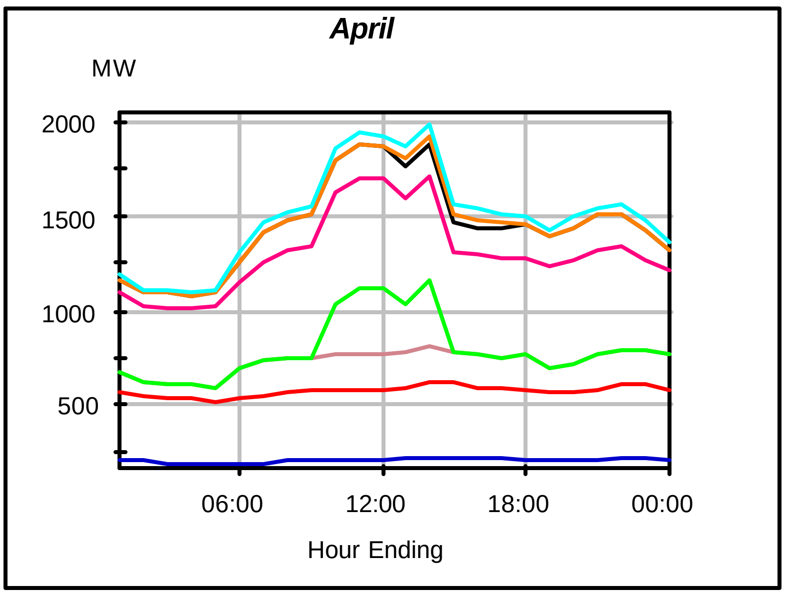


Forecast Year



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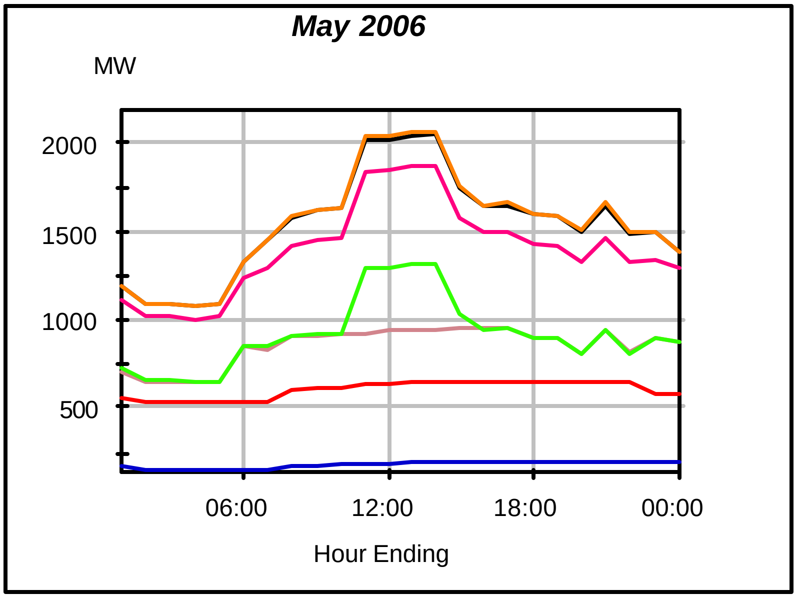

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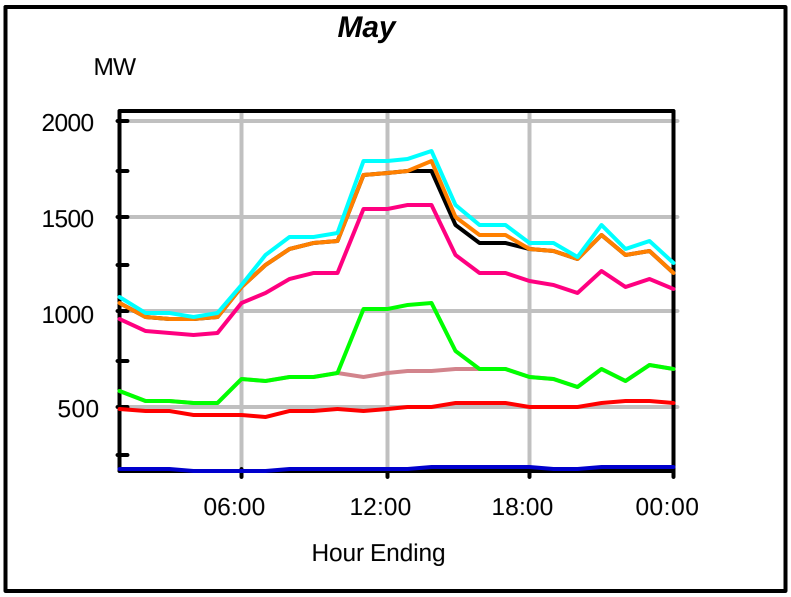

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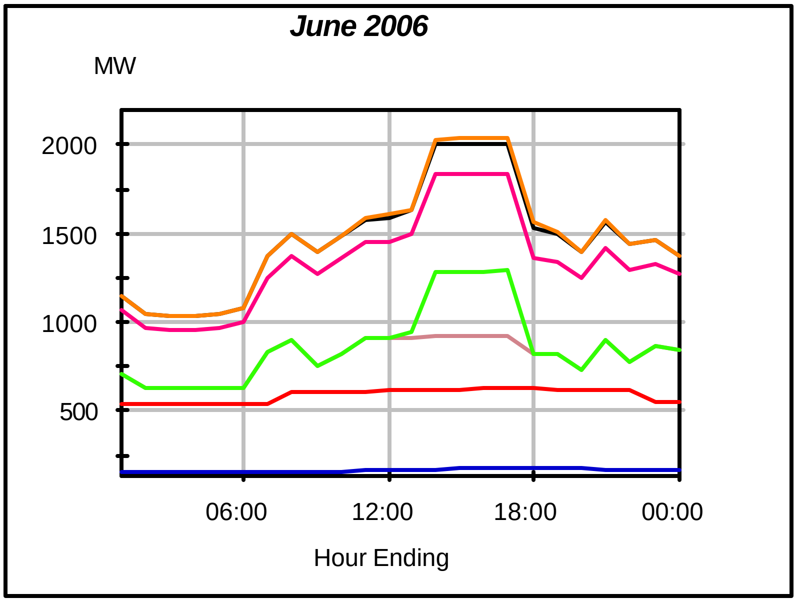
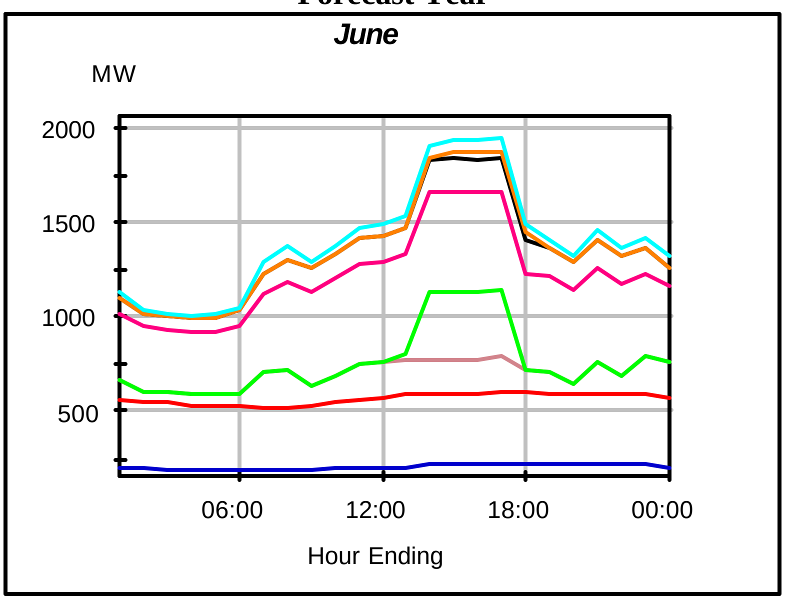
Average Weekday

Base Year



Forecast Year



- - - - EP
- - - - Plus RP
- - - - Plus R&D Firm
- - - - Plus R&D Peaking
- - - - Plus Munis& Coops
- - - - Plus OOS Firm
- - - - Plus OOS Peaking
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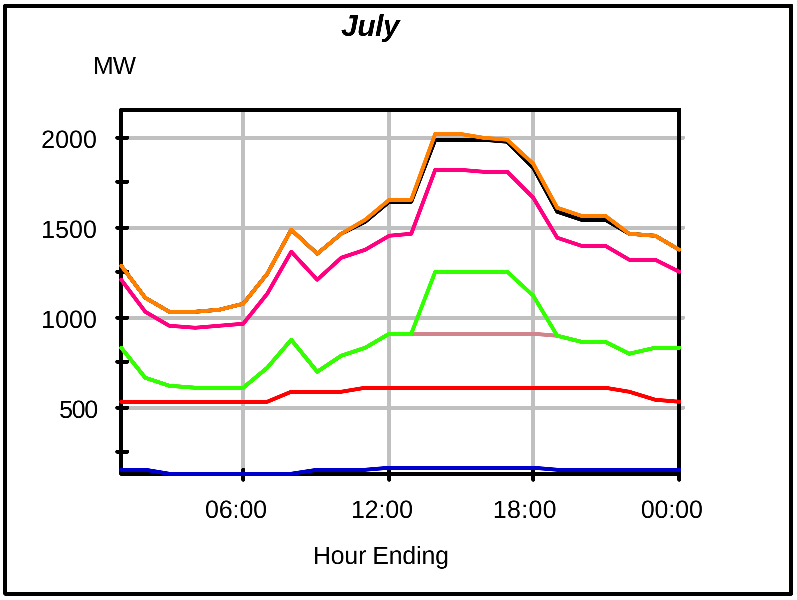
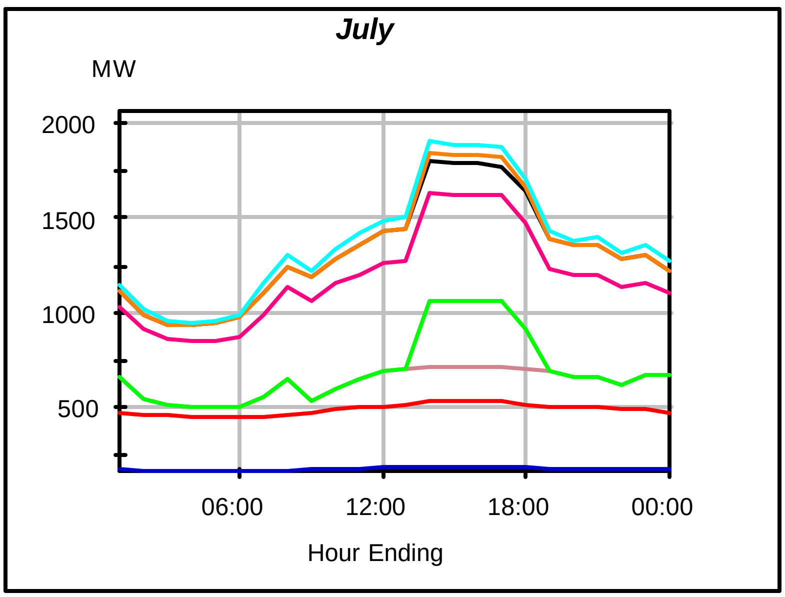
Average Weekend

Base Year



Forecast Year



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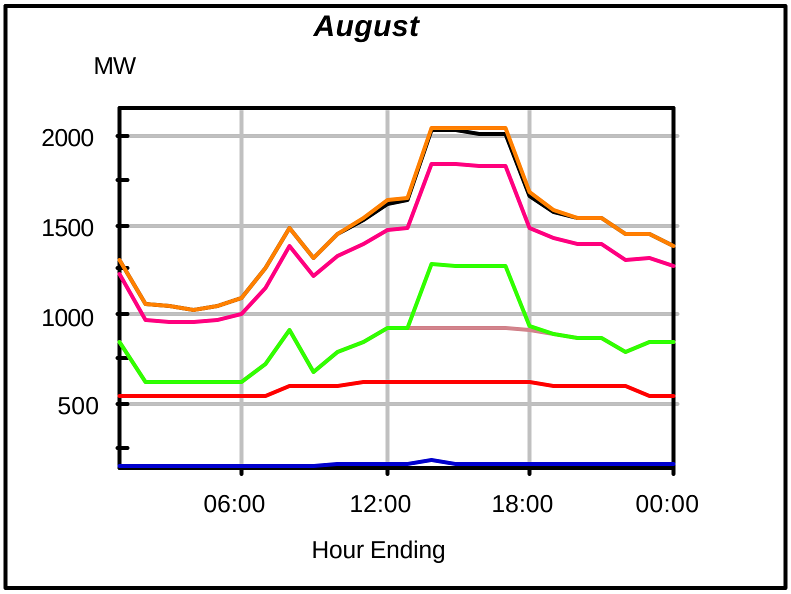
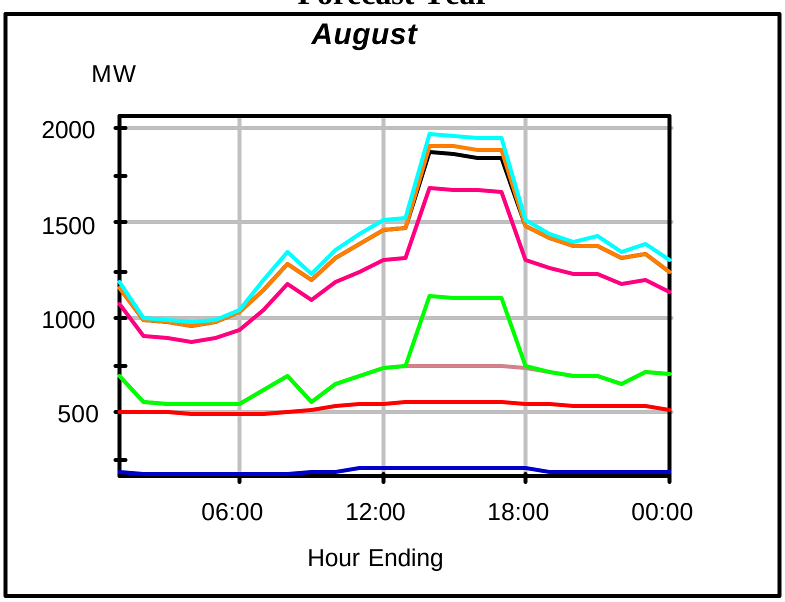
Average Weekend

Base Year



Forecast Year



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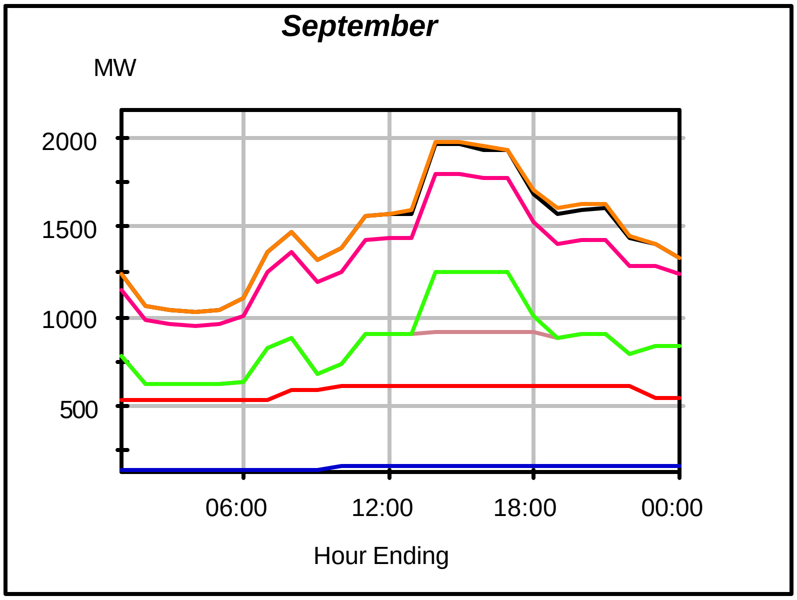

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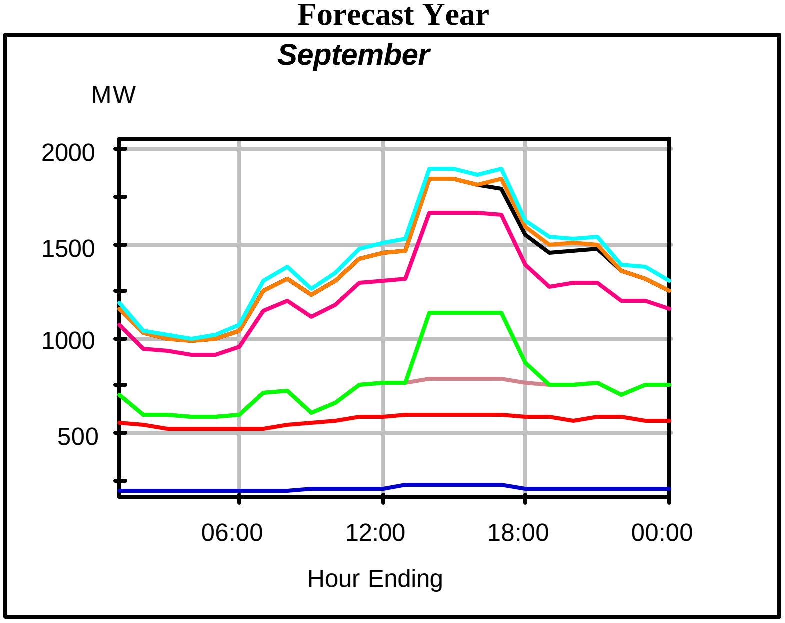

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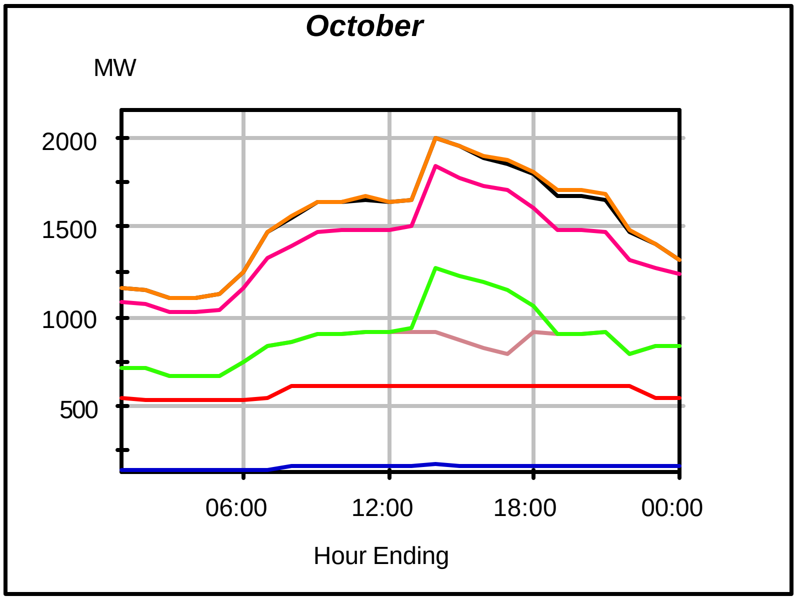

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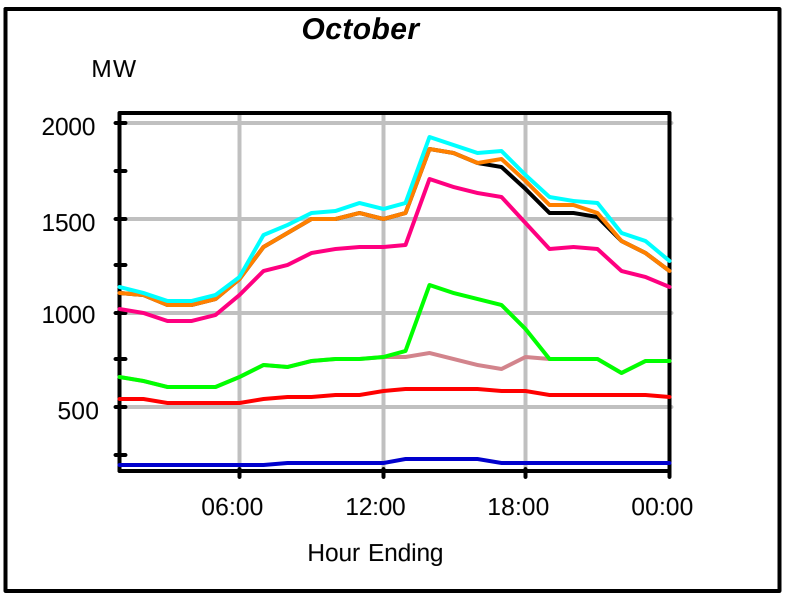

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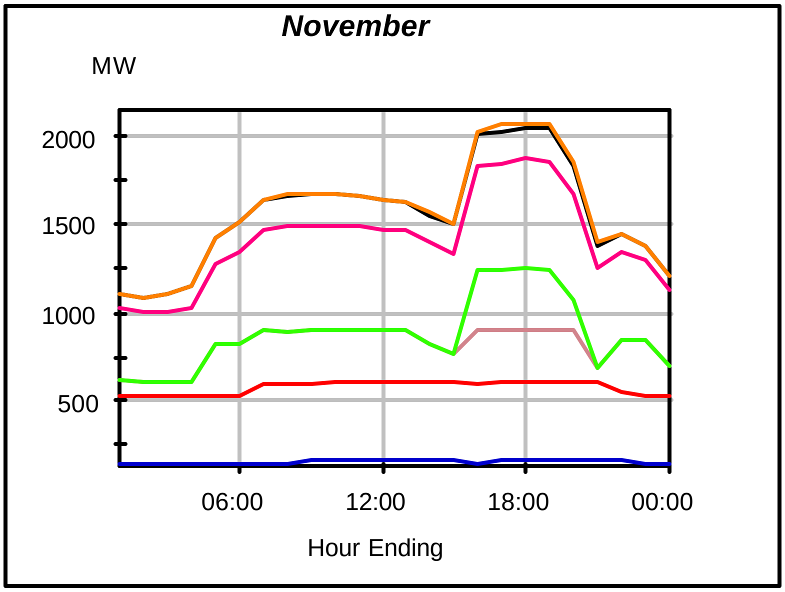

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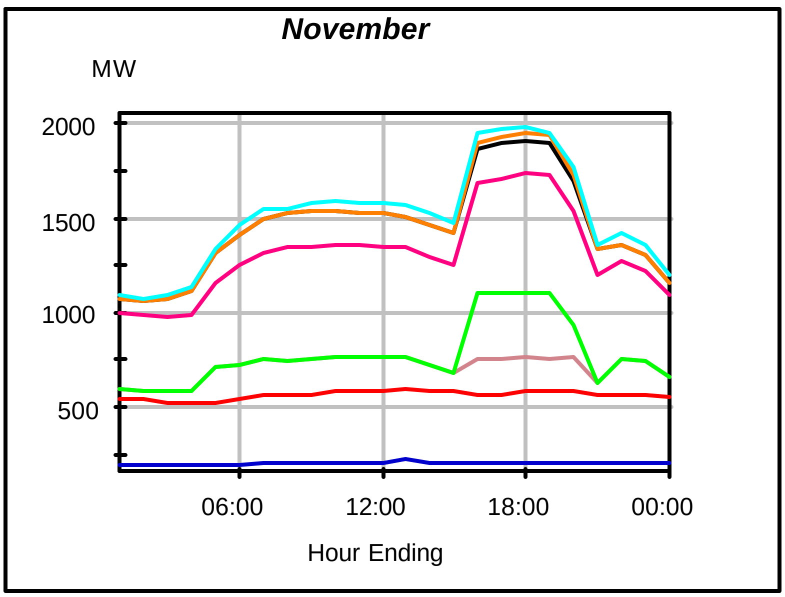

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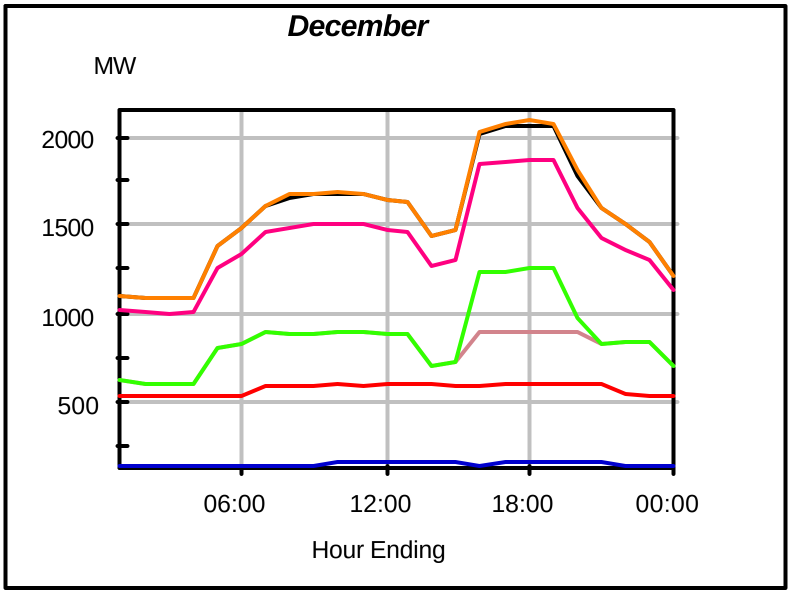

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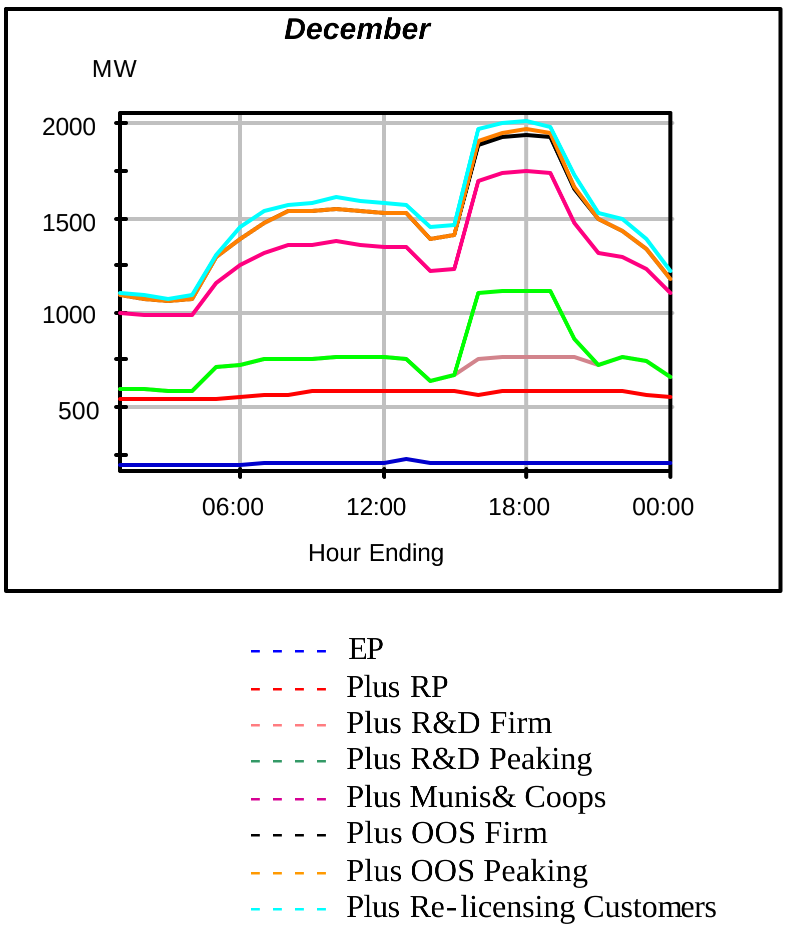

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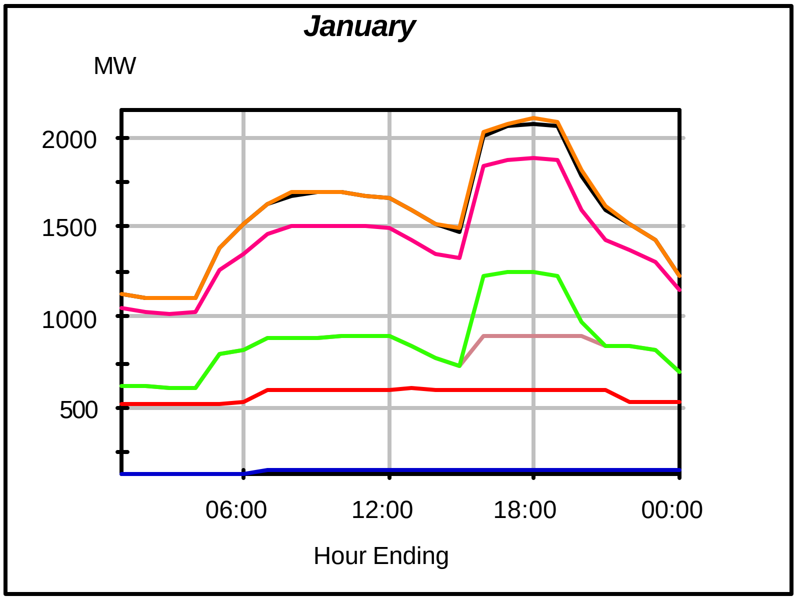

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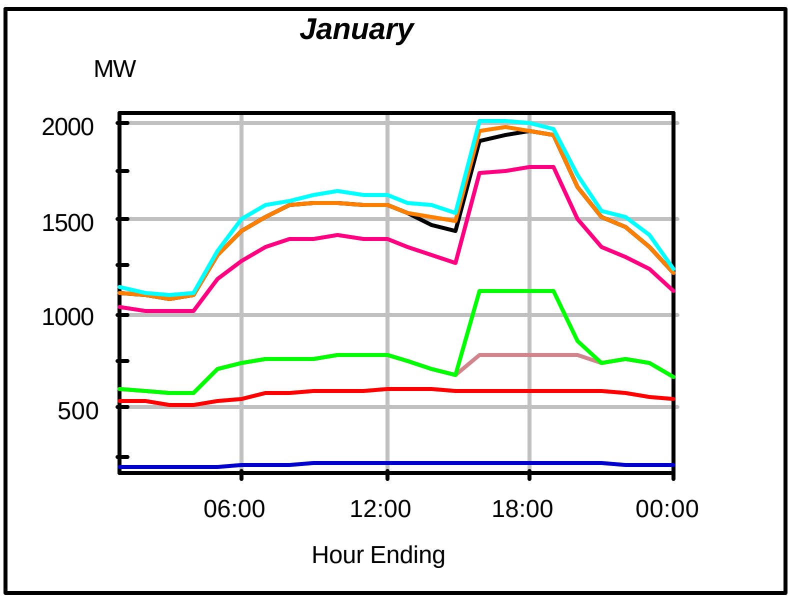

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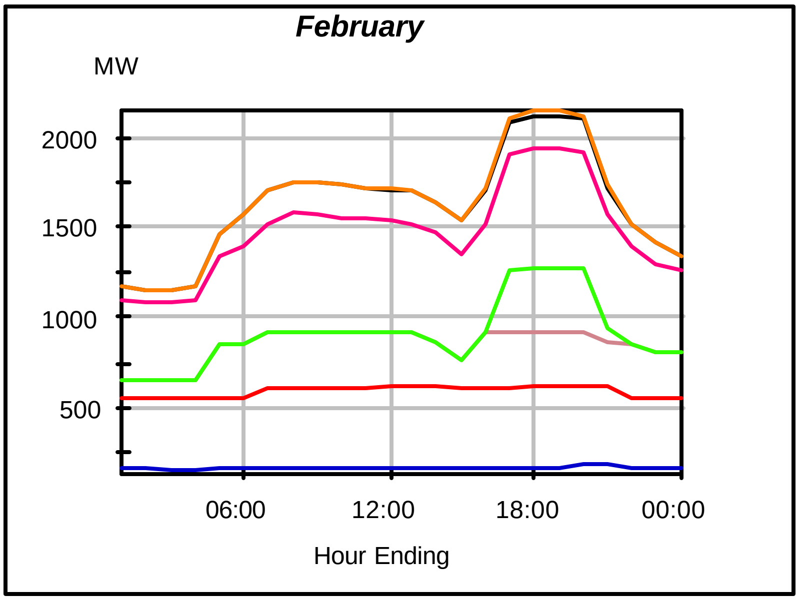

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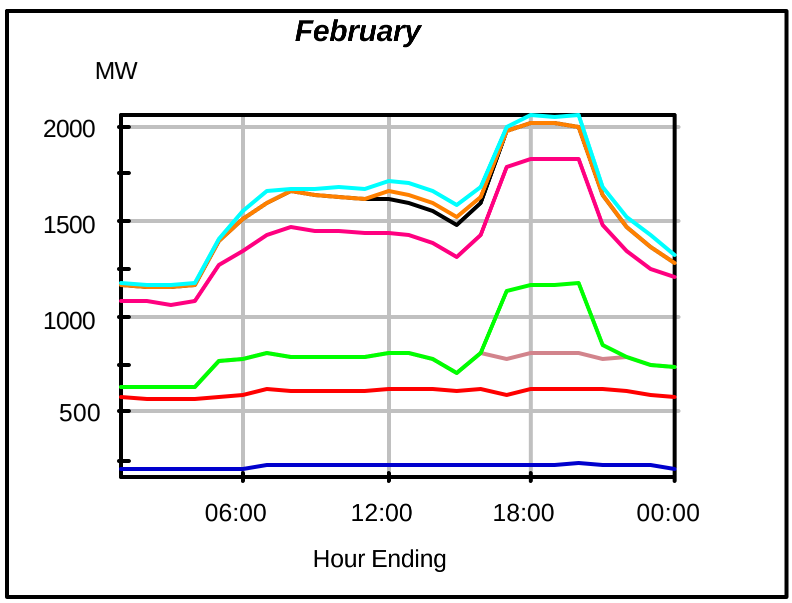

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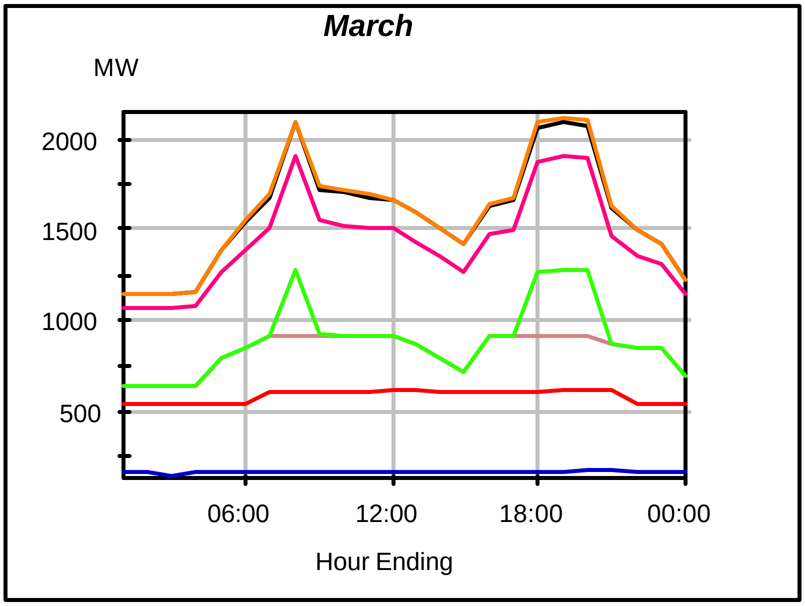

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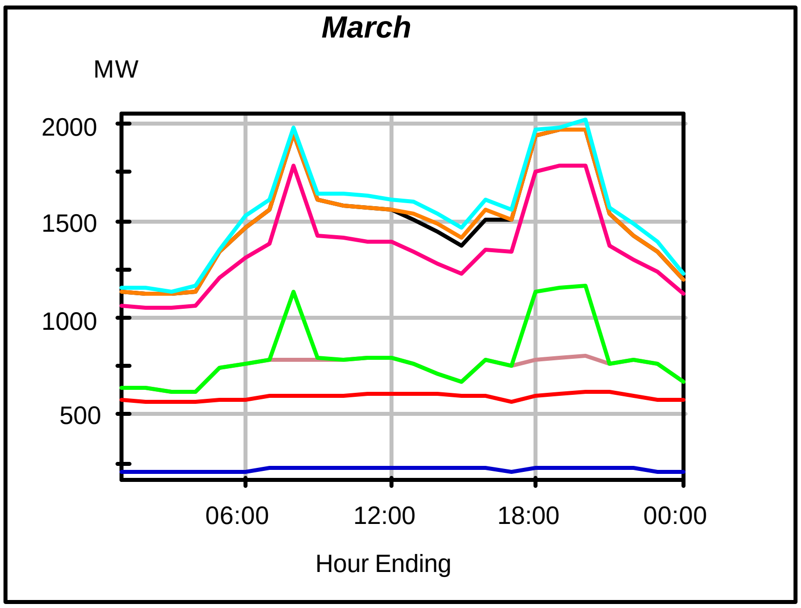

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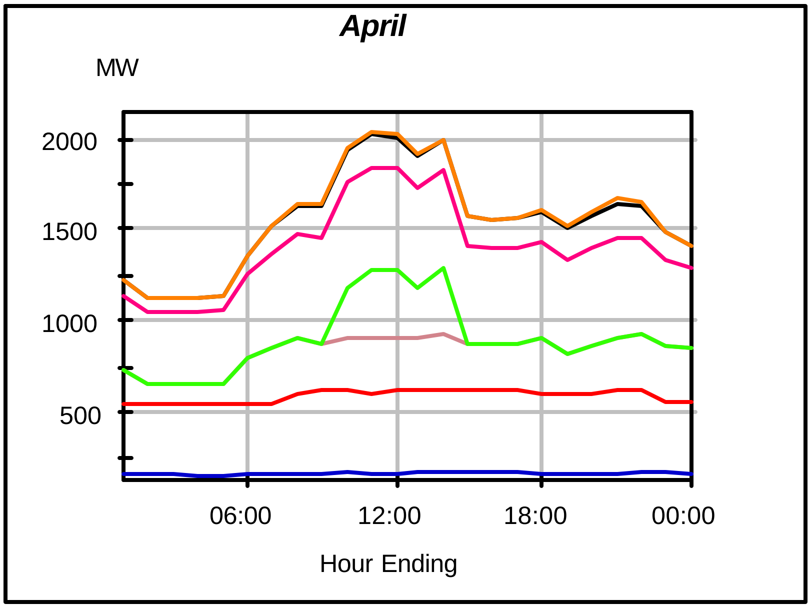

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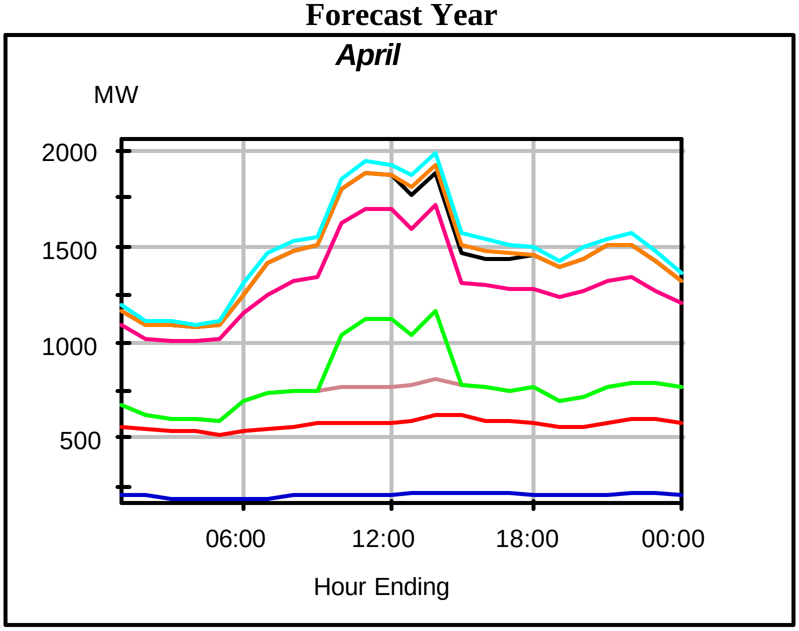

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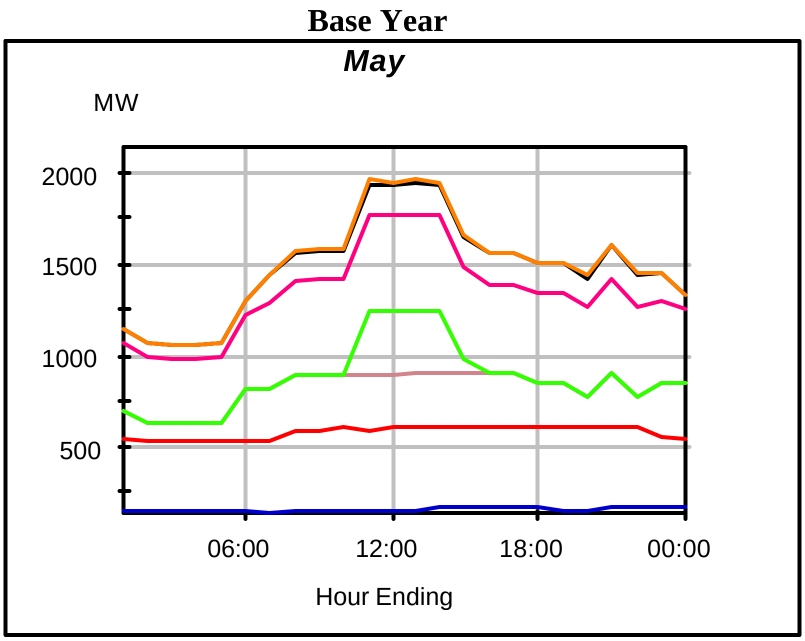

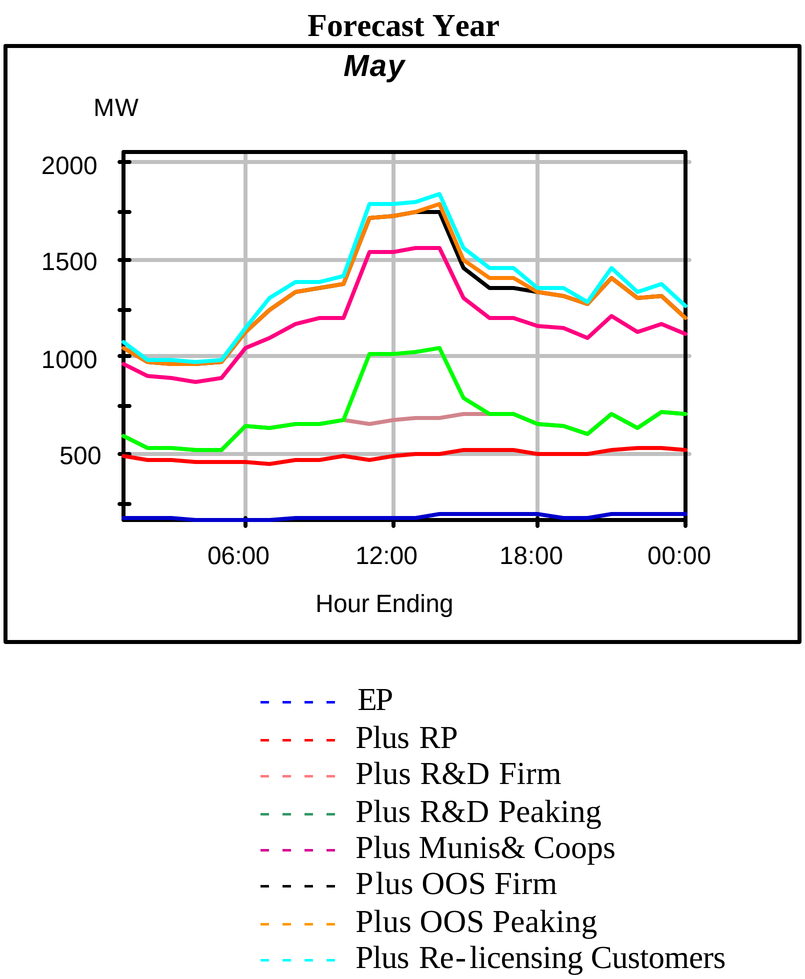

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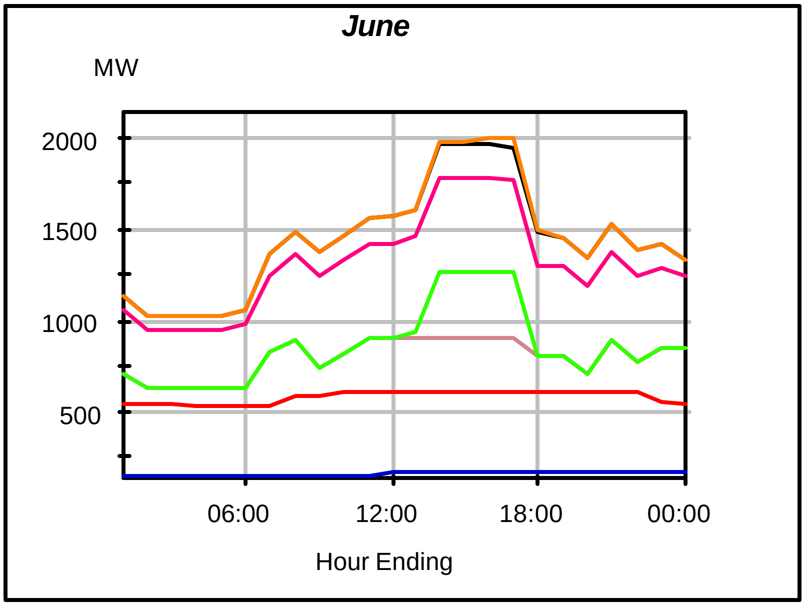

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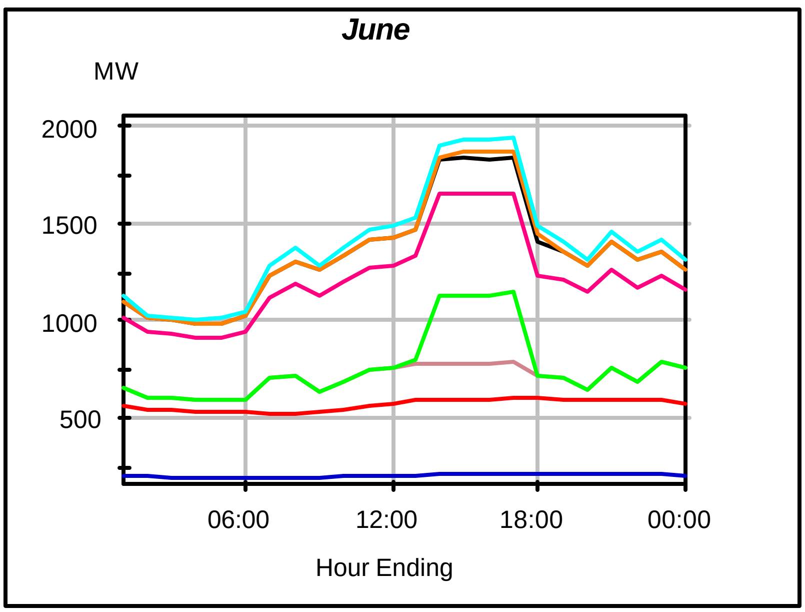

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