Exhibit No.:
Witness: David L. Stowe
Type of Exhibit: Rebuttal Testimony
Issues: Cost of Service
Sponsoring Party: Missouri Industrial Energy Consumers
Case No.: ER-2008-0318

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area.	))))))	**Case No. ER-2008-0318**

Rebuttal Testimony and Schedules of

David L. Stowe

on Cost of Service

On Behalf of

Missouri Industrial Energy Consumers

BRUBAKER & ASSOCIATES, INC.
CHESTERFIELD, MO 63017

Project 8983
October 14, 2008

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area.	)	Case No. ER-2008-0318

STATE OF MISSOURI)
) SS
COUNTY OF ST. LOUIS)

Affidavit of David L. Stowe

David L. Stowe, being first duly sworn, on his oath states:

1. My name is David L. Stowe. I am a consultant with Brubaker & Associates, Inc., having its principal place of business at 16690 Swingley Ridge Road, Suite 140, Chesterfield, Missouri 63017. We have been retained by the Missouri Industrial Energy Consumers in this proceeding on their behalf.

2. Attached hereto and made a part hereof for all purposes is my rebuttal testimony and schedules which were prepared in written form for introduction into evidence in Missouri Public Service Commission Case No. ER-2008-0318.

3. I hereby swear and affirm that the testimony and schedules are true and correct and that they show the matters and things that they purport to show.

David L. Stowe

Subscribed and sworn to before me this 13th day of October, 2008.

TAMMY S. KLOSSNER
Notary Public - Notary Seal
STATE OF MISSOURI
St. Charles County
My Commission Expires: Mar. 14, 2011
Commission # 07024862

Notary Public

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Rebuttal Testimony of David L. Stowe

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A David L. Stowe. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, Missouri 63017.

Q ARE YOU THE SAME DAVID L. STOWE WHO HAS PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?

A Yes. I have previously filed direct testimony on distribution system issues.

Q IS YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE OUTLINED IN YOUR DIRECT TESTIMONY?

A Yes. This information is included in Appendix A.

Q ON WHOSE BEHALF ARE YOU PRESENTING THIS REBUTTAL TESTIMONY?

A This testimony is presented on behalf of the Missouri Industrial Energy Consumers ("MIEC").

Q HAVE YOU REVIEWED THE TESTIMONY OF OPC WITNESS BARBARA MEISENHEIMER ON THE SUBJECT OF HER DEVELOPMENT OF SPECIFIC ALLOCATION FACTORS?

A Yes.

Q DO YOU HAVE REBUTTAL TO MS. MEISENHEIMER'S TESTIMONY?

A Yes, I do. I disagree with the methods Ms. Meisenheimer has used to develop the "time-of-use ("TOU")" demand allocation factors. These allocation factors are used in the OPC Cost of Service Study ("COSS") to distribute AmerenUE's ("AmerenUE" or "Company") fixed generation and transmission costs to its customer classes.

Q PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A My rebuttal testimony may be summarized as follows:

1. The data used to develop the TOU allocation factors is counter-intuitive; reflecting relatively high costs during off-peak periods, and relatively low costs during peak demand periods.

2. When used to distribute AmerenUE's fixed (i.e., demand-related costs), the TOU factors allocate a disproportionately high cost to high load factor customers that use electricity more efficiently throughout the off-peak periods.

OPC's TOU Allocation Factors

Q PLEASE DESCRIBE THE ALLOCATION FACTORS THAT THE OPC USED TO DISTRIBUTE FIXED GENERATION AND TRANSMISSION COSTS?

A The OPC has submitted the results of two COS studies, one that uses the "average and four coincident peak ("A&4CP")" method to distribute costs, and a second study that uses a "TOU" method. OPC witness Barbara Meisenheimer describes these allocation factors when she states:

> "The first is a traditional method of allocating production costs based on a weighting of average and peak demands. The second offers an alternative production allocator based on Time of Use (TOU), similar to the TOU Demand allocator I filed in KCP&L Case No. ER-2006-0314 and Ameren Case No. ER-2007-0002." (Direct Testimony of Barbara Meisenheimer, page 2, lines 10-14)

In my rebuttal testimony, I will focus on my review of the underlying data that was used to develop the TOU allocation factors.

Q DOES MS. MEISENHEIMER EXPLAIN HOW SHE ALLOCATES CAPACITY AND ENERGY COSTS IN THE "TOU" STUDY?

A Only in very general terms. Ms. Meisenheimer claims that the TOU method is "consistent" with a method mentioned in a document published in January 1992 by the National Association of Regulatory Utility Commissioners ("NARUC"). This document, titled the Electric Utility Cost Allocation Manual ("NARUC Manual"), describes a variety of time differentiated embedded cost of service methods, including one called the Probability of Dispatch ("POD").

> "The probability of dispatch (POD) method is primarily a tool for analyzing cost of service by time periods. The method requires analyzing an actual or estimated hourly load curve for the utility and identifying the generating units that would normally be used to serve each hourly load. (Direct Testimony of Barbara A. Meisenheimer, page 7, lines 17-20)

No specific instructions are provided in the NARUC Manual to aid the analyst in performing a POD analysis, therefore a review of Ms. Meisenheimer's workpapers was necessary. My review revealed that an hourly assignment of capacity costs of generation plants was made using the RealTime® production cost modeling software. This software was used to identify an hourly capacity cost component for each plant, and to determine the output of each plant during each hour of the year. The load output level of each plant, for each hour, was then totaled and divided into the

identified capacity cost component. This per unit capacity cost component was then multiplied times the output of each plant in each hour in order to allocate capacity costs to each hour that a plant ran. This calculation was repeated for each plant and a total capacity cost was developed for each hour. These hourly capacity costs were then assigned to customer classes based on class loads in each hour.

Q HAVE YOU BEEN ABLE TO ANALYZE THE RESULTS OF OPC'S CAPACITY COST ASSIGNMENT TO HOURS?

A Yes. Please refer to Schedules DLS-COS-R-1 through DLS-COS-R-4, attached to this testimony.

Q PLEASE EXPLAIN THESE SCHEDULES.

A These schedules show an hourly profile comparison of the OPC's TOU capacity cost assignment versus the hourly load. The hourly load is represented by a blue line with the large squares, while the generation capacity costs are represented by a red line with pyramids.

Q WHAT PROMPTED YOU TO DEVELOP THESE SCHEDULES?

A The TOU factors that result from the process I have described above can only be as accurate and valid as the underlying data, Realizing this, I performed an analysis of the data underlying the OPC TOU allocation factors to determine if the generation capacity cost data, and its relationship to the hourly loads, was consistent with what is generally known to be true from real world experience.

For example, consider the generation capacity costs during the hour of the system's annual peak demand. Since this is the hour when the combined demand of

AmerenUE's customer base is at its highest level, it is reasonable that AmerenUE would be running more of its plants and/or making more purchases than at any other time during the year. Consequently, one would expect to find a relatively high capacity cost during these peak hours. Conversely, one could reasonably expect to find a relatively low capacity cost during periods when the combined demand of AmerenUE's customer base is relatively low.

I analyzed the data underlying the OPC's TOU results during the days in which the highest system peak demands occurred, as well as the days in which the highest hourly generation capacity costs occurred. I focused on hours where unusually high costs occur at times when the system demand was relatively low, and when unusually low costs occurred at times when the system demand was relatively high. By performing these types of analyses, I was able to identify a number of anomalies in the data that warrant further study.

Q WHAT ANOMALIES DID YOU FIND IN THE OPC'S GENERATION CAPACITY COST DATA?

A I found that the highest generation capacity cost during the weather normalized test year occurred on Wednesday, August 15, at 4:00 p.m. Surprisingly, this does not correspond to the annual peak demand for that year. Instead, the peak on August 15 was 341 MW below the annual peak demand that occurred on July 10.

Schedule DLS-COS-R-1 shows the hourly demand and total generation capacity costs for August 15, 2007. Schedule DLS-COS-R-1 clearly shows a significant peak in demand occurs at around 4:00 p.m., and that a corresponding peak in capacity costs occurred beginning at 1:00 p.m. This data suggests that peak generation units which burned high cost fuel were brought online and/or high cost

replacement power purchases were made at 1:00 p.m. when the peak demand was approximately 90% of its peak for the day. In addition, I note that the peak demand that occurred at 4:00 p.m. on August 15, was approximately 93% of the annual peak demand. In other words, the OPC's underlying data indicates that when the system peak demand was approximately 84% of its highest annual level, capacity costs began to rise sharply to its highest level in the year. This is counter-intuitive.

Q HAVE YOU REVIEWED OTHER SIGNIFICANT HOURS THROUGHOUT THE TEST YEAR?

A Yes. I also reviewed peak demand and capacity costs during the days of the two highest peak demands, as well as during a weekend period when the peak demand is traditionally low. The underlying data indicates a maximum peak demand of 7,948 MW occurred at 2:00 p.m. on July 10, 2007. This is shown on Schedule DLS-COS-R-2. The capacity cost during this hour was less than 25% of the peak cost that occurred on August 15. The second highest system peak of 7,936 MW occurred at 4:00 p.m. on July 19 when the capacity cost was only 12% of the peak cost that occurred on August 15 (Schedule DLS-COS-R-3).

I also reviewed the relationship between the peak demand and capacity costs during the weekends when demands are traditionally relatively low. I reviewed the data for Sunday, December 16, 2007 and found that the peak demand of 6,113 MW occurred at 5:00 p.m., and fell very gradually until approximately 8:00 p.m. The capacity cost during this period peaked to a level nearly 350% higher than the capacity cost during the peak demand period (Schedule DLS-COS-R-4).

Q HOW DO THESE ANOMALIES AFFECT THE FINAL TOU ALLOCATION FACTORS?

A The anomalies I have identified all have the effect of increasing capacity costs during off-peak time periods, and decreasing capacity costs during peak demand time periods. The TOU allocation factors that are derived from this data will distribute significantly higher costs to classes that contribute a larger portion of the off-peak demand and a lower percentage of the on-peak demand. In short, the OPC's TOU allocation factors will distribute a larger portion of costs to the high load factor customers.

Q WHAT OTHER PROBLEMS HAVE YOU FOUND WITH THE DATA UNDERLYING THE OPC'S TOU ALLOCATION FACTORS?

A The demand values used by the OPC to develop the TOU allocation factors do not correspond to the demand values used by the OPC for its A&4CP allocation factors, nor do they correspond to the demand values used by any other party in this case. As I described earlier, the highest annual demand, as recorded in the OPC's TOU data set, occurred on July 10, 2007 and reached a peak value of 7,948 MW. However, the non-coincident peak demand, as provided in AmerenUE's COSS, occurred in August and reached 9,238 MW. The coincident peak demand, again as provided in AmerenUE's COSS, also occurred in August and reached the level of 8,485 MW.

The underlying data that the OPC relied upon to develop its TOU allocation factors not only shows a peak demand occurring a month earlier than the load data provided by AmerenUE, but the peak demand used by the OPC differs from that submitted by the Company by as much as 14%.

Q WHAT HAVE YOU CONCLUDED FROM YOUR REVIEW OF THE DATA THAT UNDERLIES THE OPC'S TOU ALLOCATION FACTORS?

A The data indicates combinations of peak demands and capacity costs that are counter-intuitive and even anomalous, and although Ms. Meisenheimer's discussion of TOU may loosely reference a method mentioned in the NARUC Manual, the data used to calculate the final TOU allocation factors fly in the face of the concepts described by that Manual.

Given this profile of capacity cost assignments, OPC's "TOU" method cannot reasonably be described as following cost-causation principles. It is unreasonable to suggest that loads during off-peak periods, such as during weekends, cause AmerenUE to incur high generation capacity costs. Similarly, it is unreasonable to suggest that AmerenUE's capacity costs will remain at a fraction of its peak value, even while the customer load requires the Company to bring high cost, peaking units online. Rather, it is the peak loads occurring during the day, especially the highest ones that occur in the summer, that drive the need for capacity additions and relate to high capacity costs.

Rather than being "cost-causation," OPC's "TOU" allocation methodology is an <u>assignment</u> method which puts the same per kilowatt ("kW") capacity cost of a generation facility into every hour of the year that it runs.

Q DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A Yes, it does.

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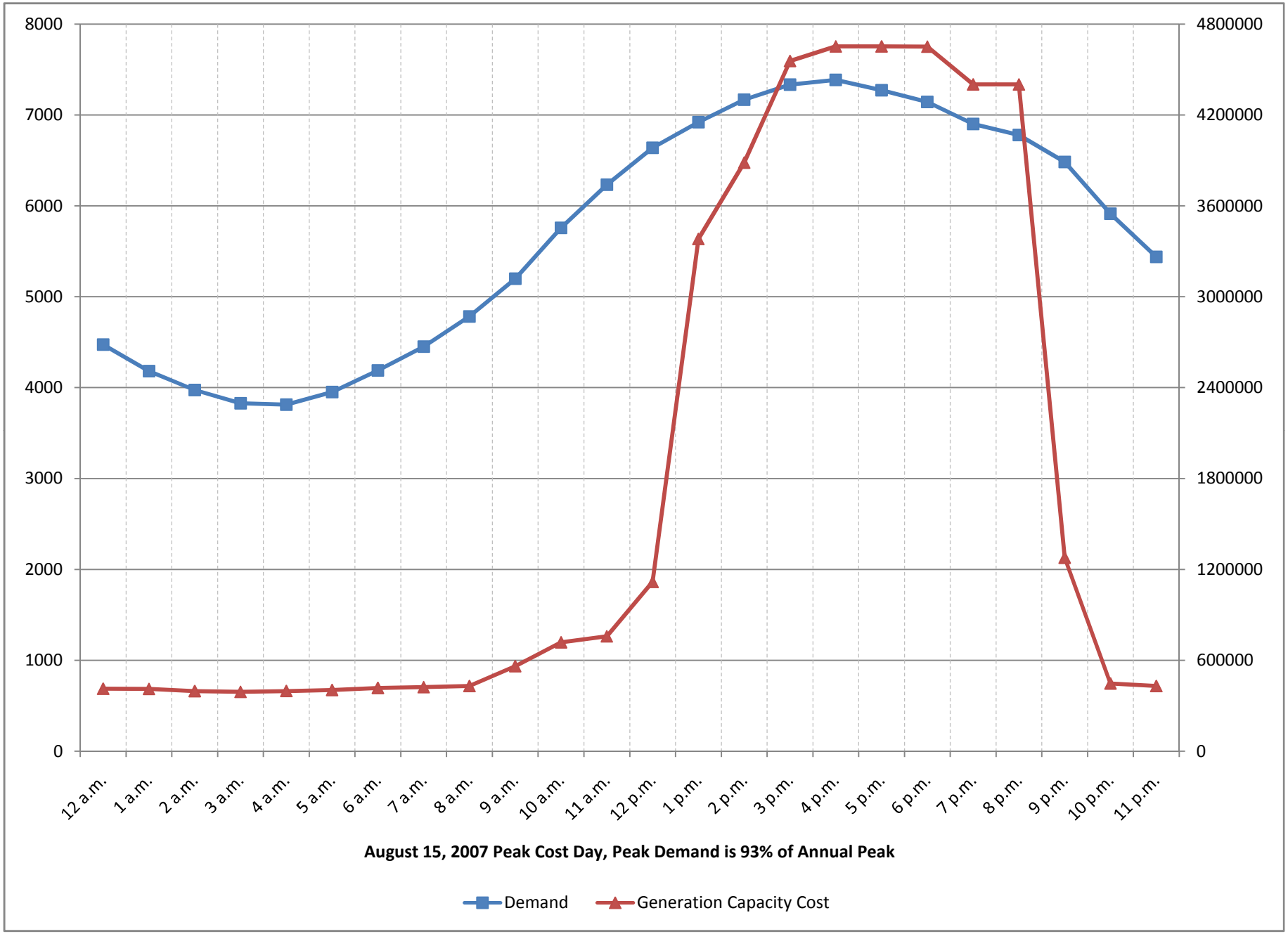
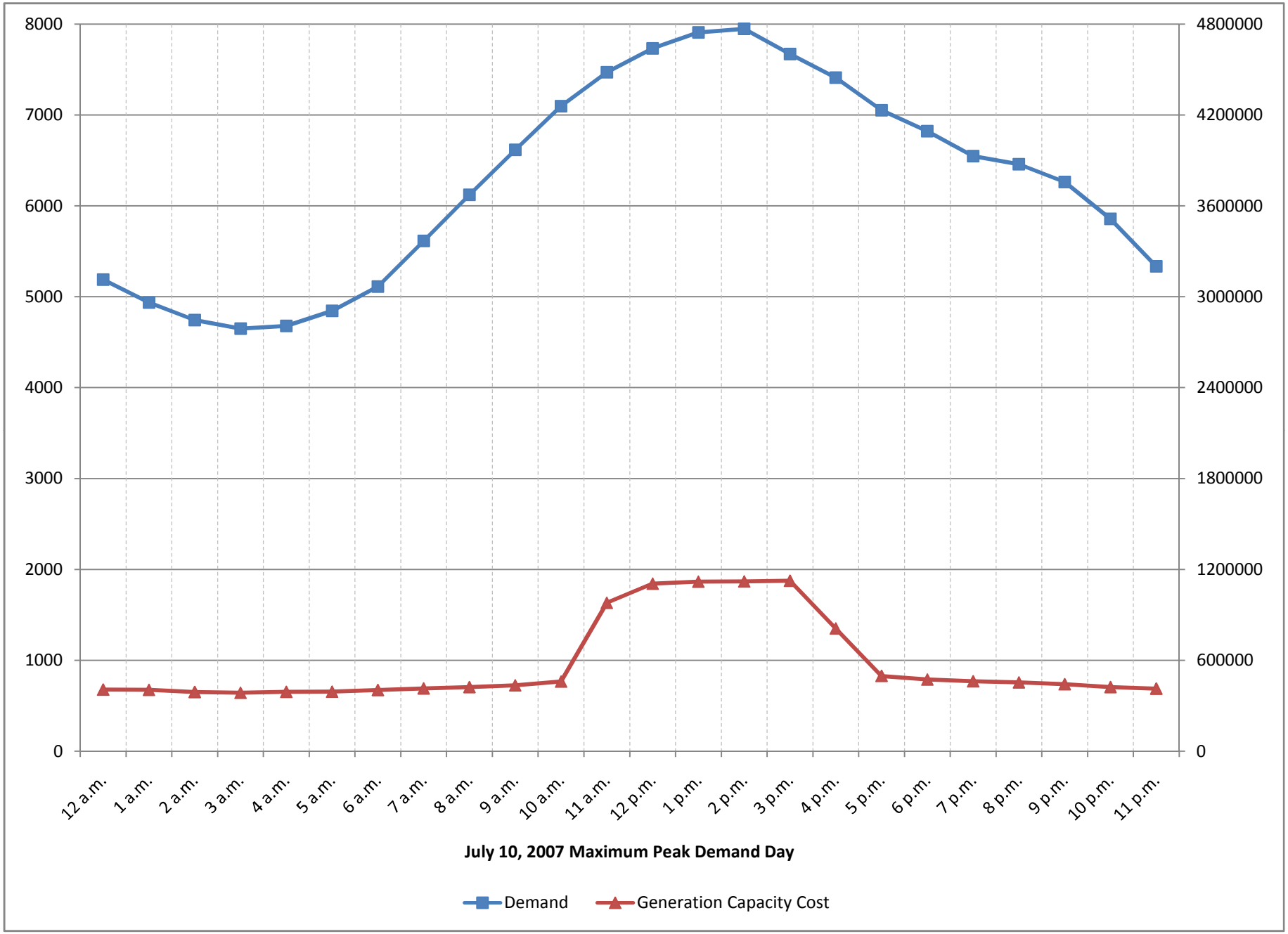
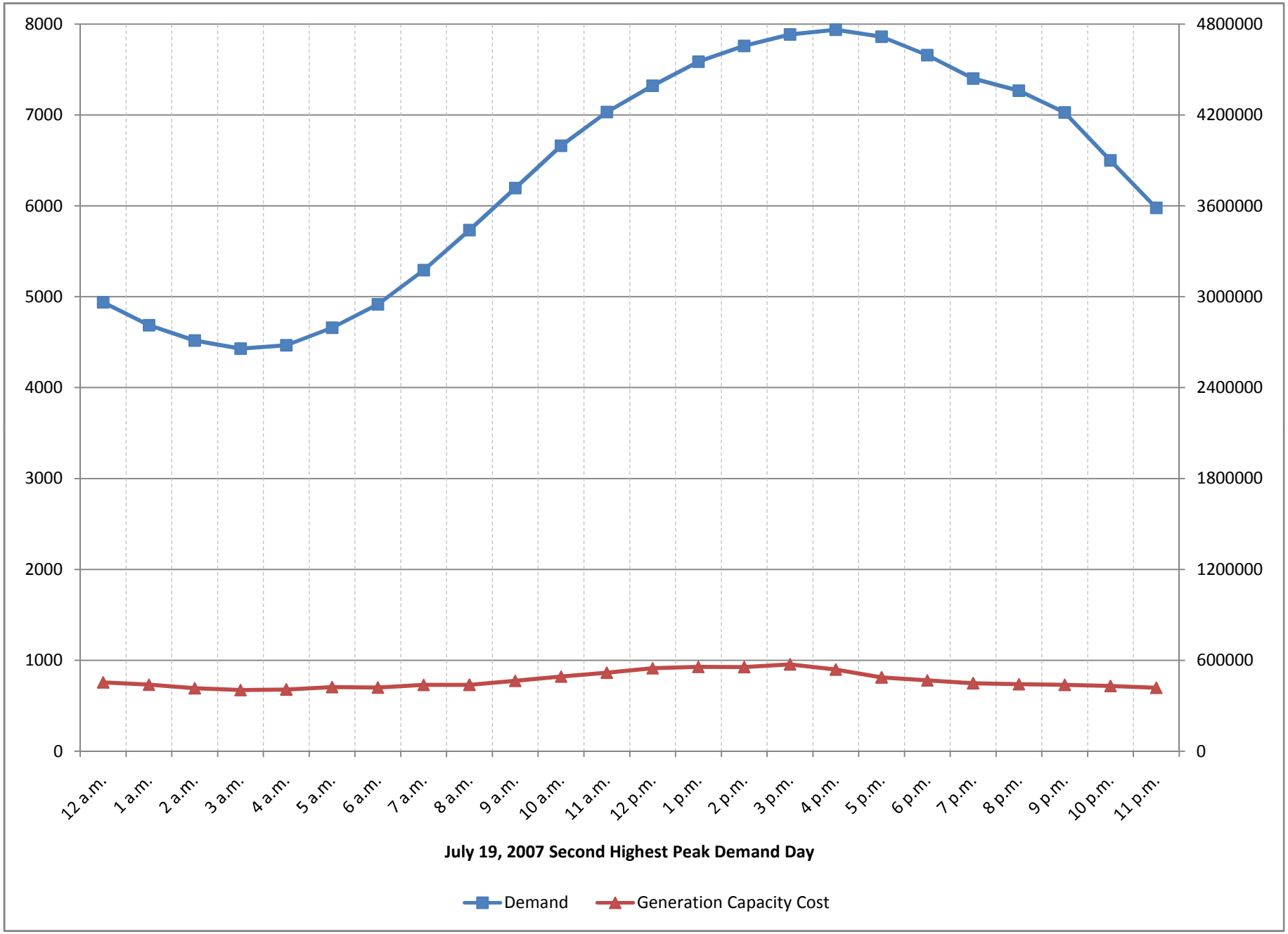


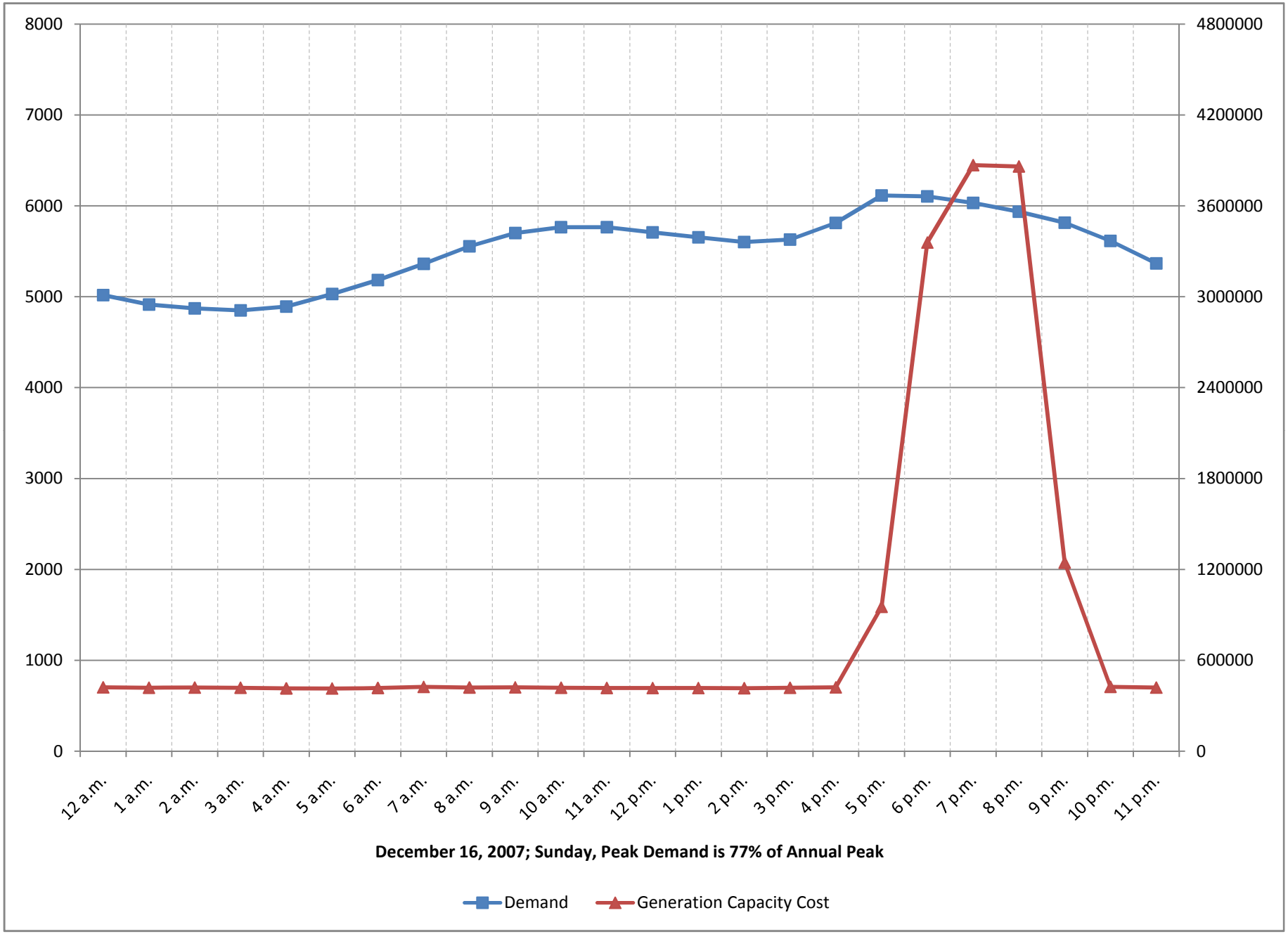
Schedule DLS-COS-R-1



Schedule-DLS COS-R-2



Schedule DLS-COS-R-3



Schedule DLS-COS-R-4