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April 30, 2014

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HAND DELIVERED

RECEIVED
APR 30 2014
PUBLIC SERVICE COMMISSION

Jeff R. Derouen
Executive Director
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

RE: Kentucky Power Company's 2013 Public Service Commission Annual Report And Related Filings

Dear Mr. Derouen:

Enclosed please find and accept for filing the original and ten copies of Kentucky Power Company's 2013 Annual Resource Assessment for Kentucky Power Company in accordance with the Commission's March 29, 2004 Order in Administrative Case No. 387. Included as part of this filing is the Company detailed discussion of the consideration given to price elasticity in making its forecasts. Also being filed is the original and ten copies of Kentucky Power Company's motion for confidential treatment with respect to portions of its response to Data Request No. 9.

A copy of the Kentucky Power Company 2010 FERC Form-1 and a copy of the 2010 Annual Public Service Commission Utility Financial Report for Kentucky Power Company are also enclosed.

Please do not hesitate to contact me if you have any questions.

Very truly yours,

Mark R. Overstreet

MRO

RECEIVED

APR 30 2014

PUBLIC SERVICE
COMMISSION

VERIFICATION

The undersigned, Ranie K. Wohnhas, being duly sworn, deposes and says he is the Managing Director Regulatory and Finance for Kentucky Power, that he has personal knowledge of the matters set forth in the forgoing responses for which he is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge, and belief

Ranie K. Wohnhas

Ranie K. Wohnhas

COMMONWEALTH OF KENTUCKY)
) Administrative Case No. 387
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Ranie K. Wohnhas, this the 8th day of April 2014.

Judy K Rosquist 481393

Notary Public

My Commission Expires: January 23, 2017

Kentucky Power Company

REQUEST

Actual and weather-normalized monthly coincident peak demands for the just completed calendar year. Demands should be disaggregated into (a) native load demand (firm and non-firm) and (b) off-system demand (firm and non-firm). Please provide the information for both Kentucky Power Company individually and the AEP-East Power Pool (pursuant to the Commission's December 13, 2004 Order in the Rockport UPSA extension, Case No. 2004-00420).

RESPONSE

Page 1 of Attachment 1 to this response provides actual and weather normalized 2013 monthly peak internal demands for Kentucky Power Company and AEP System-East. Kentucky Power Company and AEP System-East had 21 and 841 MW of contractual interruptible capacity, respectively.

Page 2 of Attachment 1 to this response provides actual 2013 monthly system demands for Kentucky Power and AEP System-East. The system demands include internal load and off-system sales. Weather-normalized monthly peak system demands for Kentucky Power Company and AEP System-East have not been developed and therefore, are not available.

Please note that the AEP System-East internal and system peak demands include loads for retail customers that receive generation services from an alternative supplier.

WITNESS: Ranie K Wohnhas

Kentucky Power Company and AEP System-East Zone
Actual and Weather Normalized Peak Internal Demand (MW)
2013

	Kentucky Power Company				AEP System-East Zone			
Month	Peak	Peak Day	Peak Hour	Normalized Peak	Peak	Peak Day	Peak Hour	Normalized Peak
January	1,409	1/23/2013	8	1,516	19,970	1/23/2013	8	20,007
February	1,316	2/1/2013	9	1,381	19,087	2/1/2013	9	19,517
March	1,294	3/22/2013	7	1,299	18,267	3/22/2013	7	17,886
April	1,129	4/3/2013	7	922	16,430	4/3/2013	7	14,233
May	1,022	5/31/2013	16	938	18,276	5/30/2013	16	17,158
June	1,124	6/12/2013	16	1,106	19,233	6/25/2013	16	19,621
July	1,138	7/18/2013	16	1,162	20,673	7/16/2013	16	20,837
August	1,097	8/28/2013	16	1,149	18,801	8/30/2013	16	20,381
September	1,084	9/10/2013	16	1,000	20,353	9/10/2013	15	17,840
October	978	10/26/2013	8	832	15,527	10/4/2013	14	13,980
November	1,194	11/13/2013	7	1,189	17,489	11/25/2013	8	16,410
December	1,275	12/13/2013	8	1,371	18,392	12/13/2013	8	18,323

Kentucky Power Company and AEP System-East Zone
Actual Peak System Demand (MW)
2013

	Kentucky Power Company			AEP System-East Zone		
Month	Peak	Peak Day	Peak Hour	Peak	Peak Day	Peak Hour
January	1,744	1/22/2013	8	26,233	1/25/2013	12
February	1,663	2/1/2013	9	24,681	2/1/2013	9
March	1,458	3/6/2013	10	22,216	3/6/2013	10
April	1,257	4/3/2013	7	18,487	4/3/2013	7
May	1,158	5/21/2013	16	20,640	5/30/2013	14
June	1,469	6/24/2013	15	25,793	6/24/2013	16
July	1,432	7/23/2013	15	24,662	7/10/2013	14
August	1,612	8/28/2013	15	27,041	8/30/2013	15
September	1,453	9/10/2013	15	26,208	9/10/2013	15
October	1,241	10/4/2013	17	21,728	10/4/2013	14
November	1,428	11/27/2013	18	22,012	11/26/2013	18
December	1,711	12/13/2013	9	25,270	12/12/2013	10

Kentucky Power Company

REQUEST

Load shape curves that show actual peak demands and weather-normalized peak demands (native load demand and total demand) on a monthly basis for the just competed calendar year. Please provide the information for both Kentucky Power Company individually and the AEP-East Power Pool (pursuant to the Commission's December 13, 2004 Order in the Rockport UPSA extension, Case No. 2004-00420).

RESPONSE

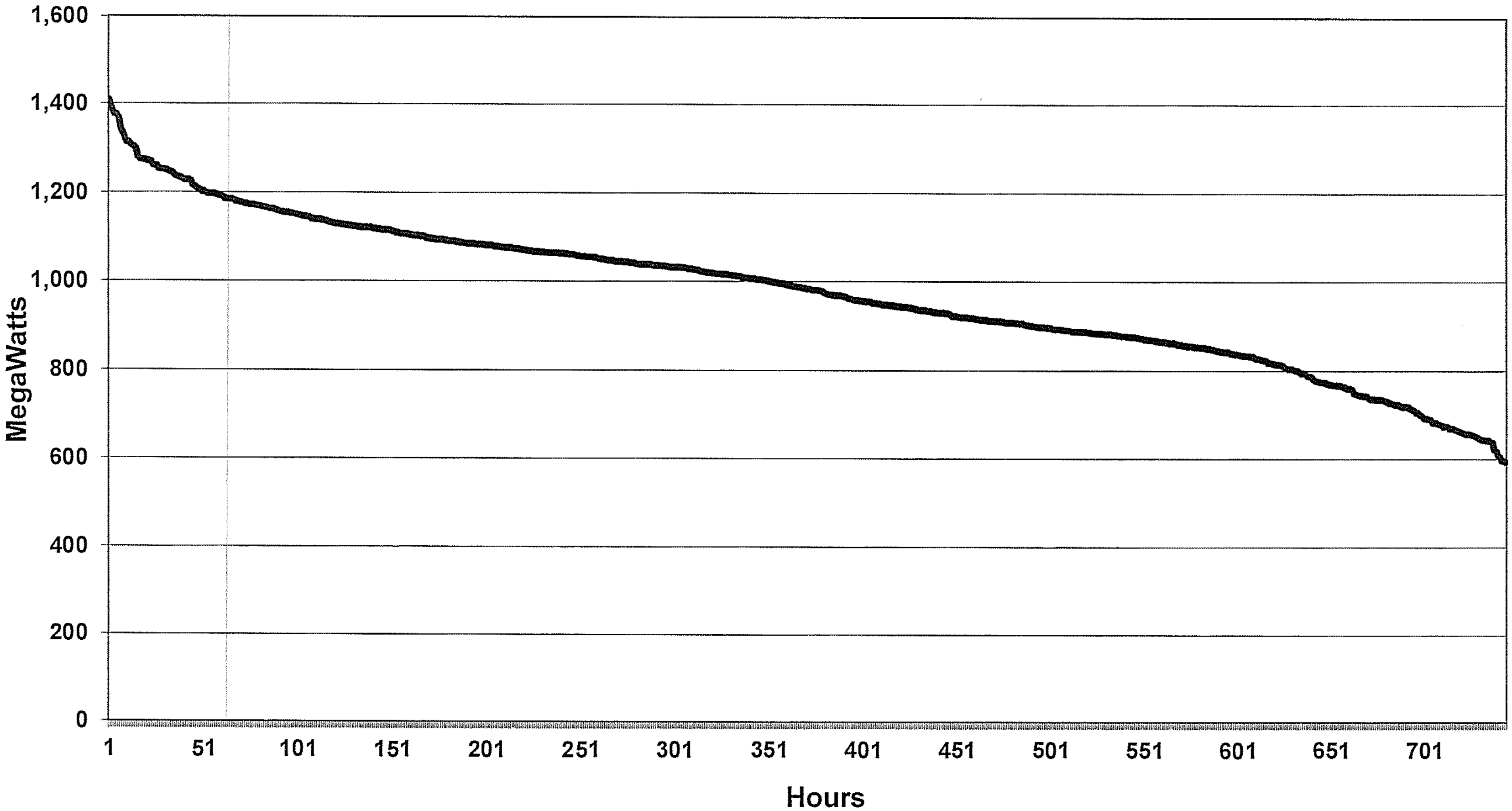
Pages 1 through 14 of Attachment 1 to this response provide 2013 monthly load duration curves for Kentucky Power Company's internal load. Pages 13 through 24 provide 2013 monthly load duration curves for Kentucky Power Company's system load. Pages 25 through 36 provide 2013 monthly load duration curves for AEP System-East's internal load. Pages 37 through 48 provide 2013 monthly load duration curves for AEP System-East's system load. The system load, for both Kentucky Power Company and AEP System-East, includes internal load and off-system sales.

Weather-normalized monthly internal peaks for Kentucky Power Company and AEP System-East are provided on Page 1 KPSC 1-1, Attachment 1. Weather-normalized system peaks have not been developed and therefore, are not available.

Please note that the AEP System-East internal and system hourly loads include loads for retail customers that receive generation services from an alternative supplier.

WITNESS: Ranie K Wohnhas

Kentucky Power Company
January 2013 Load Duration Curve
(Internal Load)



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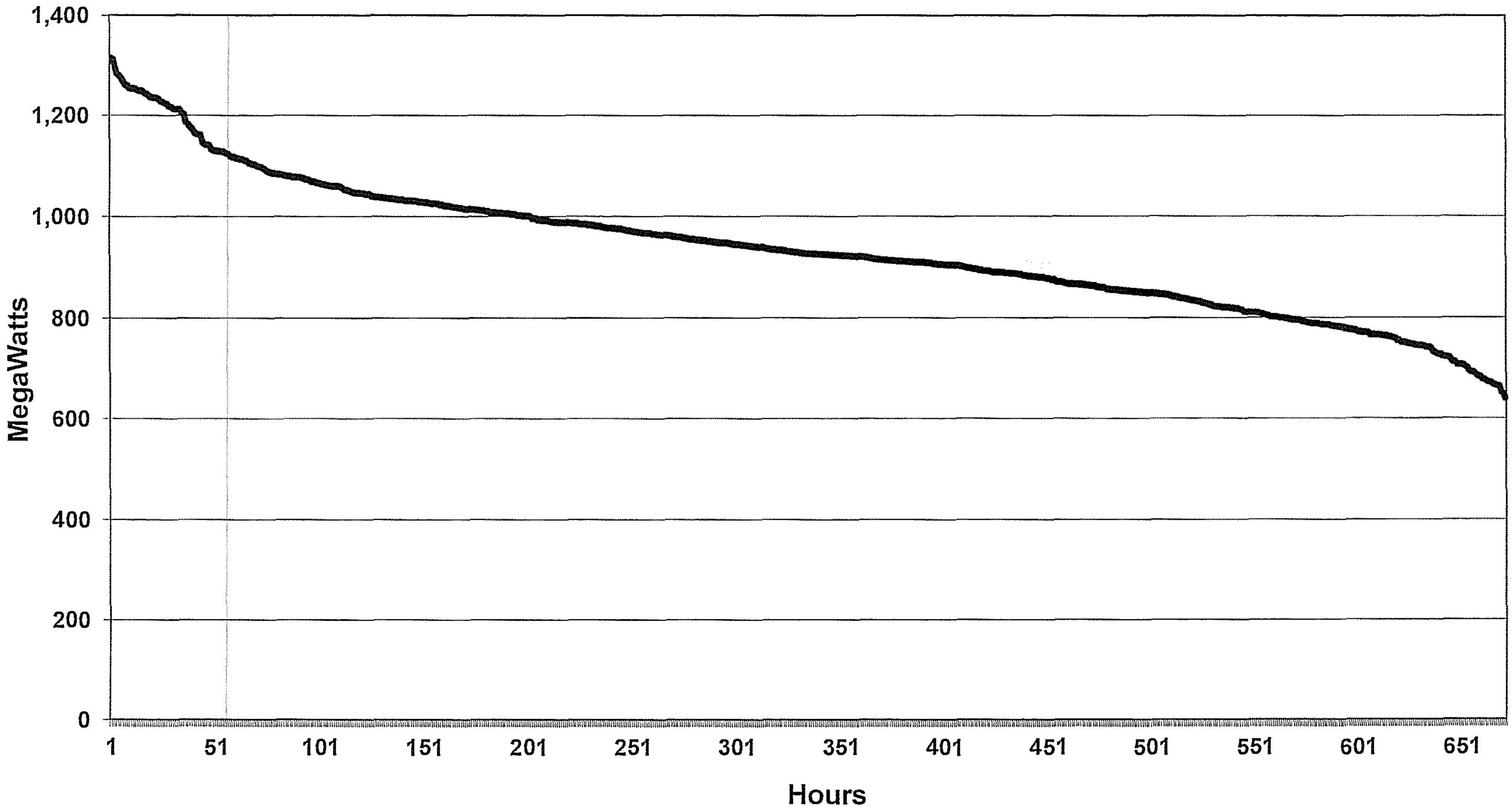
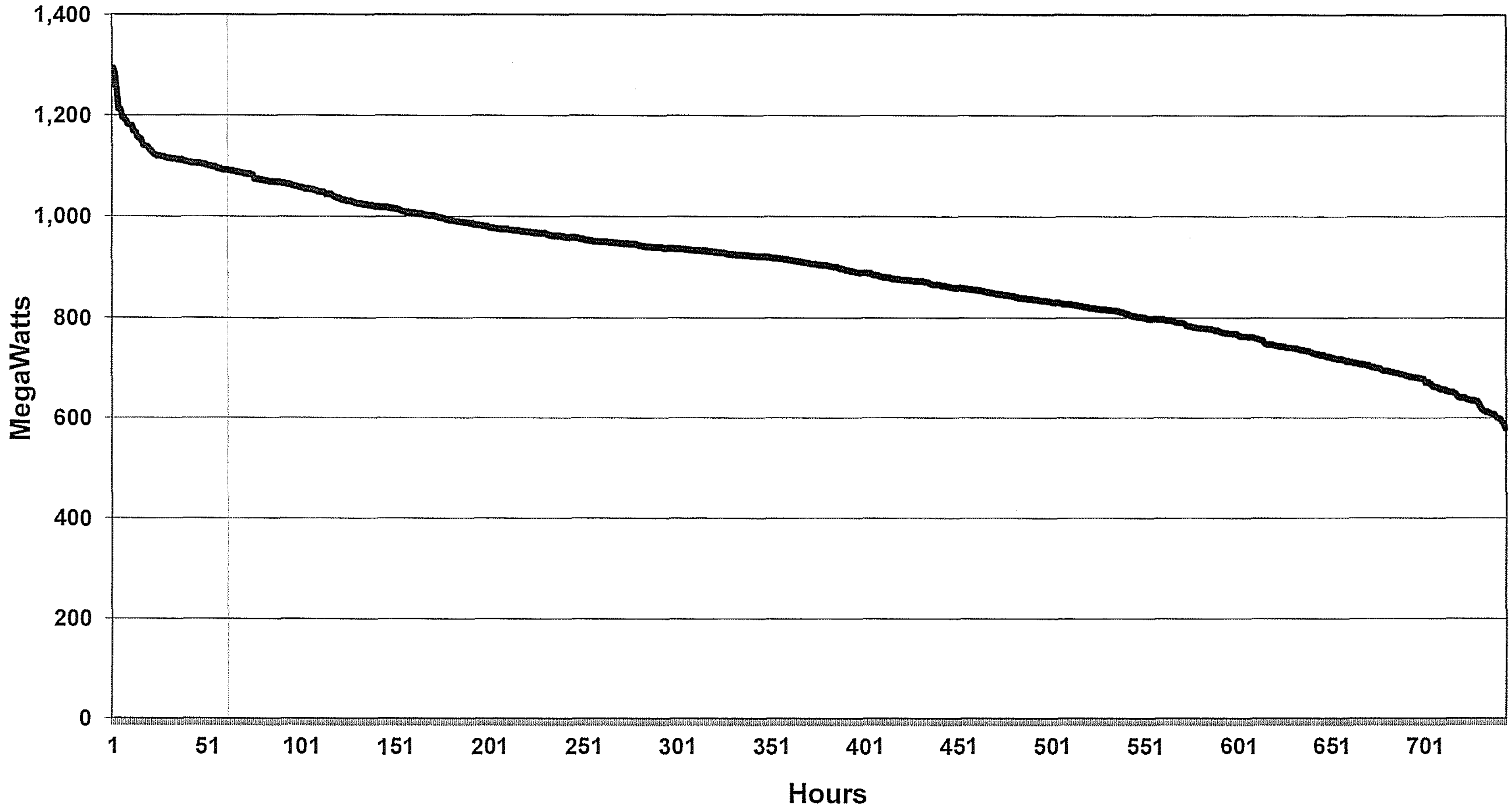
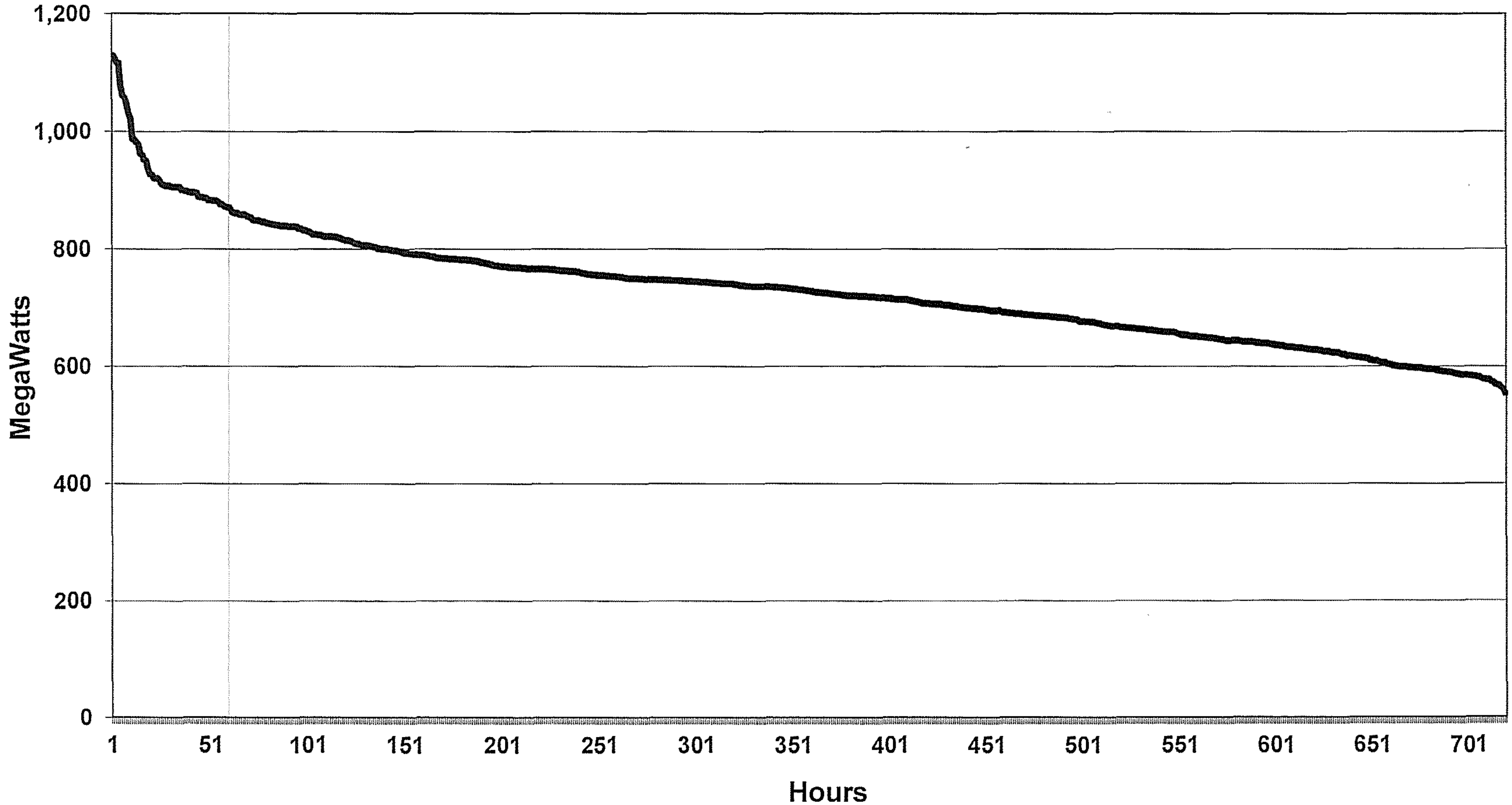
Kentucky Power Company
February 2013 Load Duration Curve
(Internal Load)



Kentucky Power Company
March 2013 Load Duration Curve
(Internal Load)



Kentucky Power Company
April 2013 Load Duration Curve
(Internal Load)



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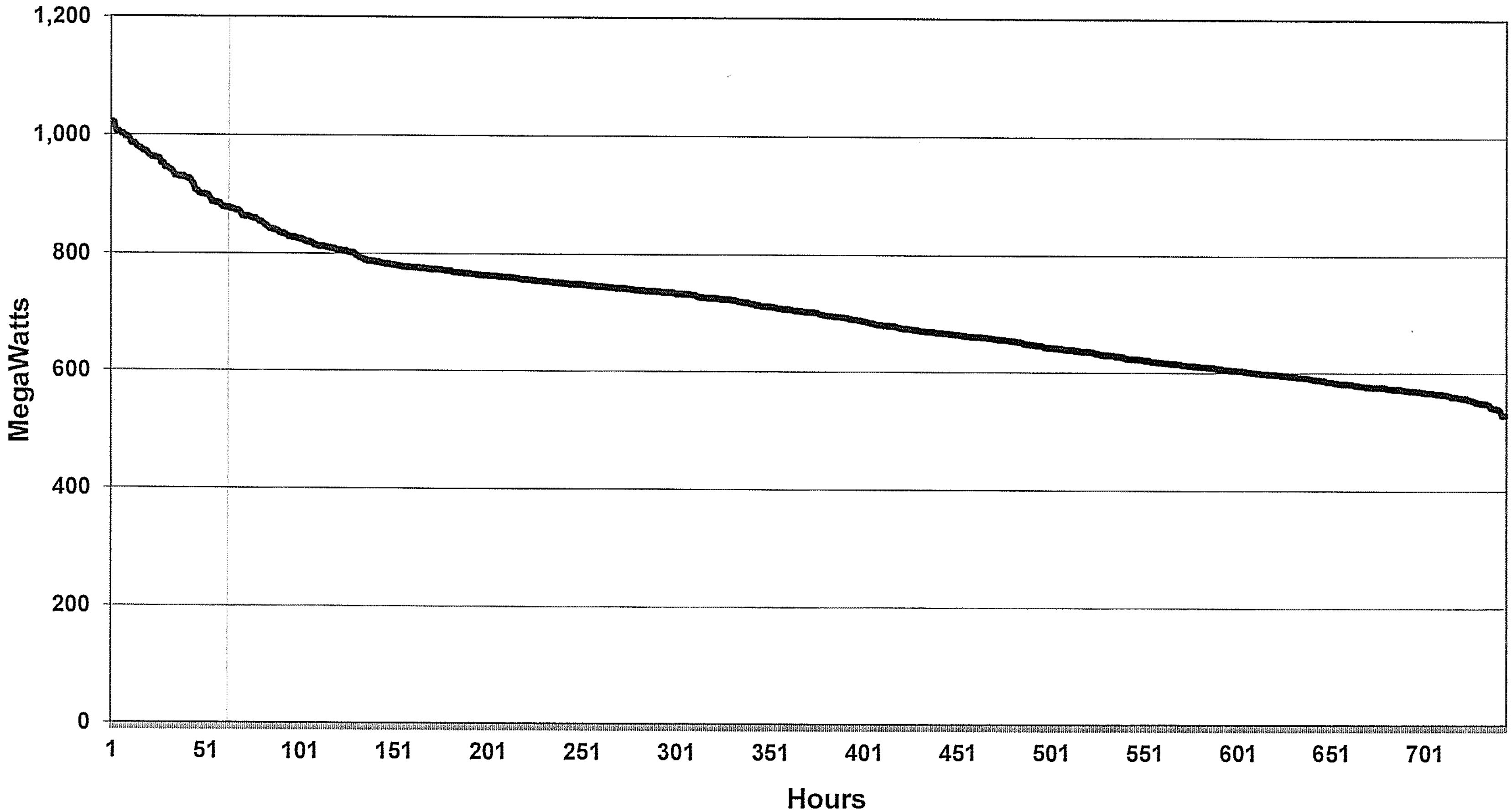
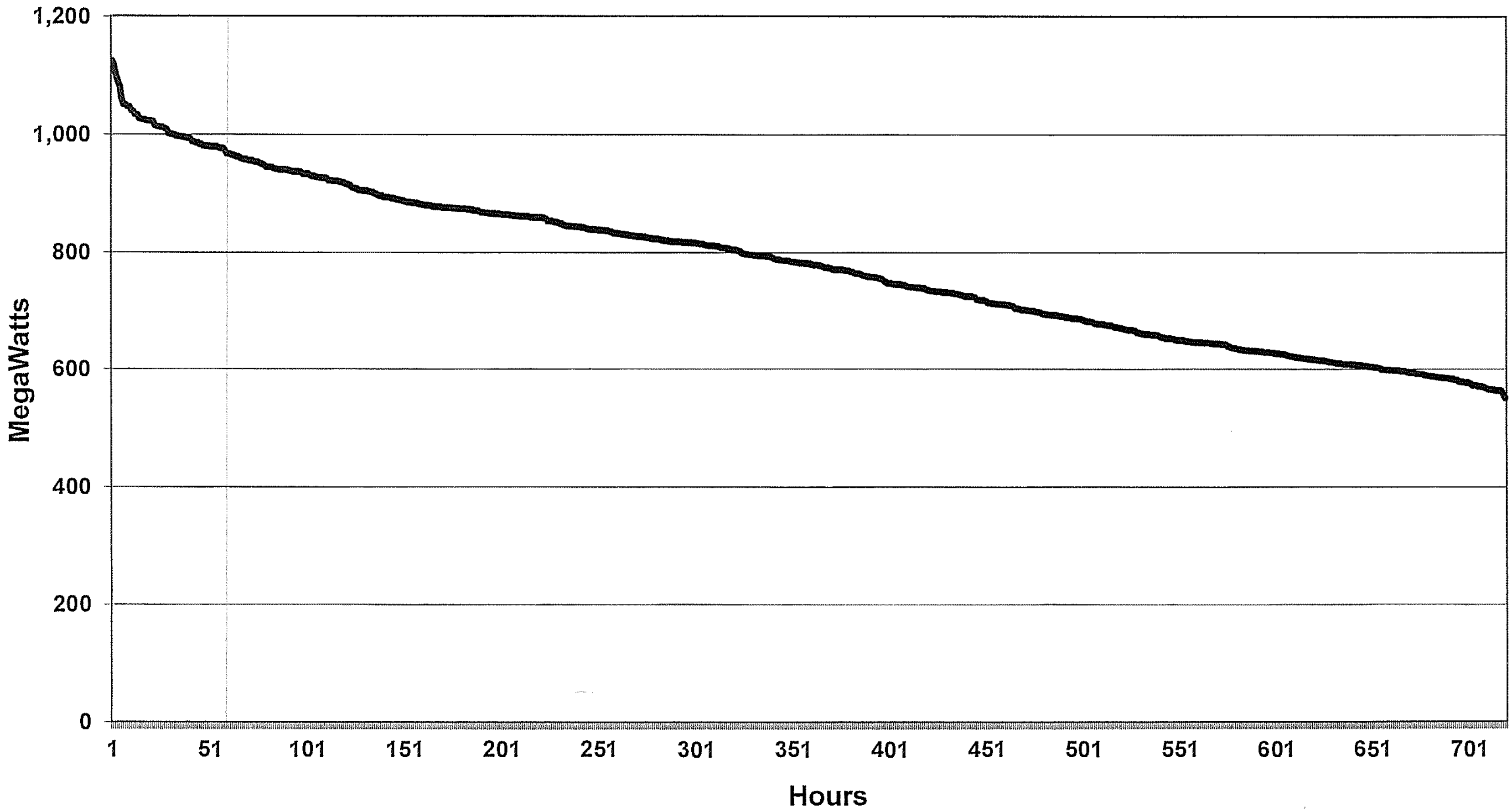
Kentucky Power Company
May 2013 Load Duration Curve
(Internal Load)



Kentucky Power Company
June 2013 Load Duration Curve
(Internal Load)



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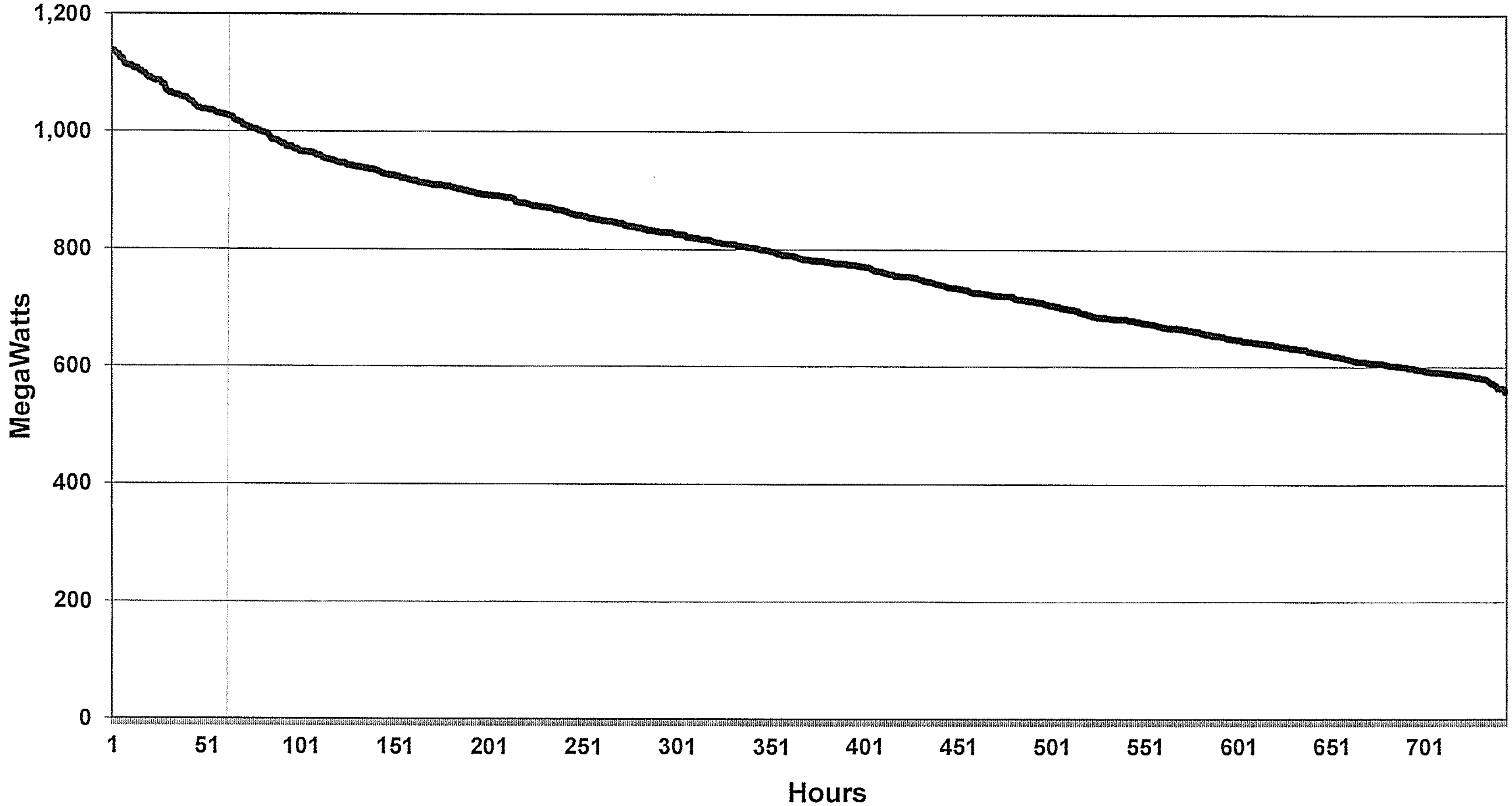
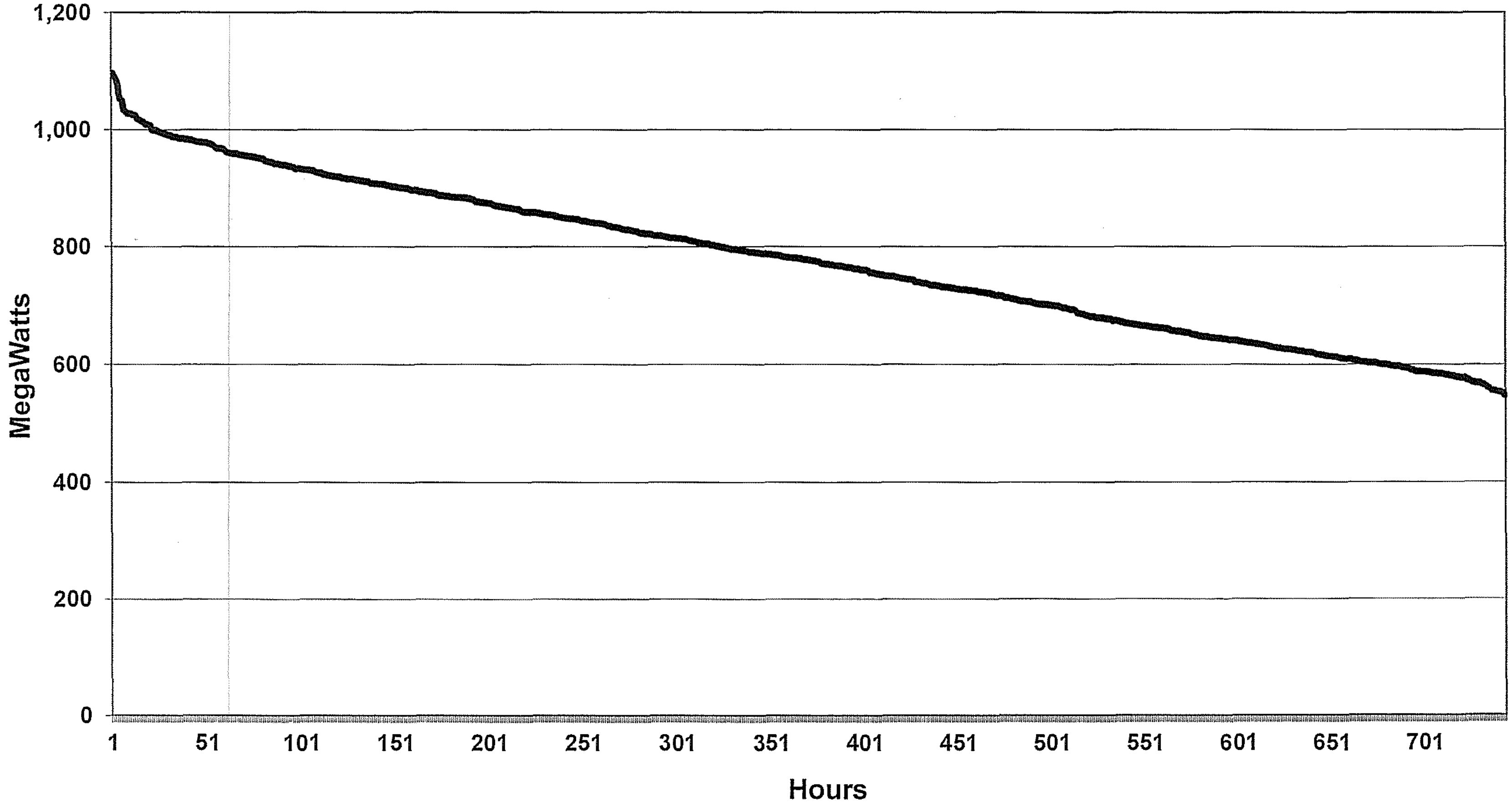
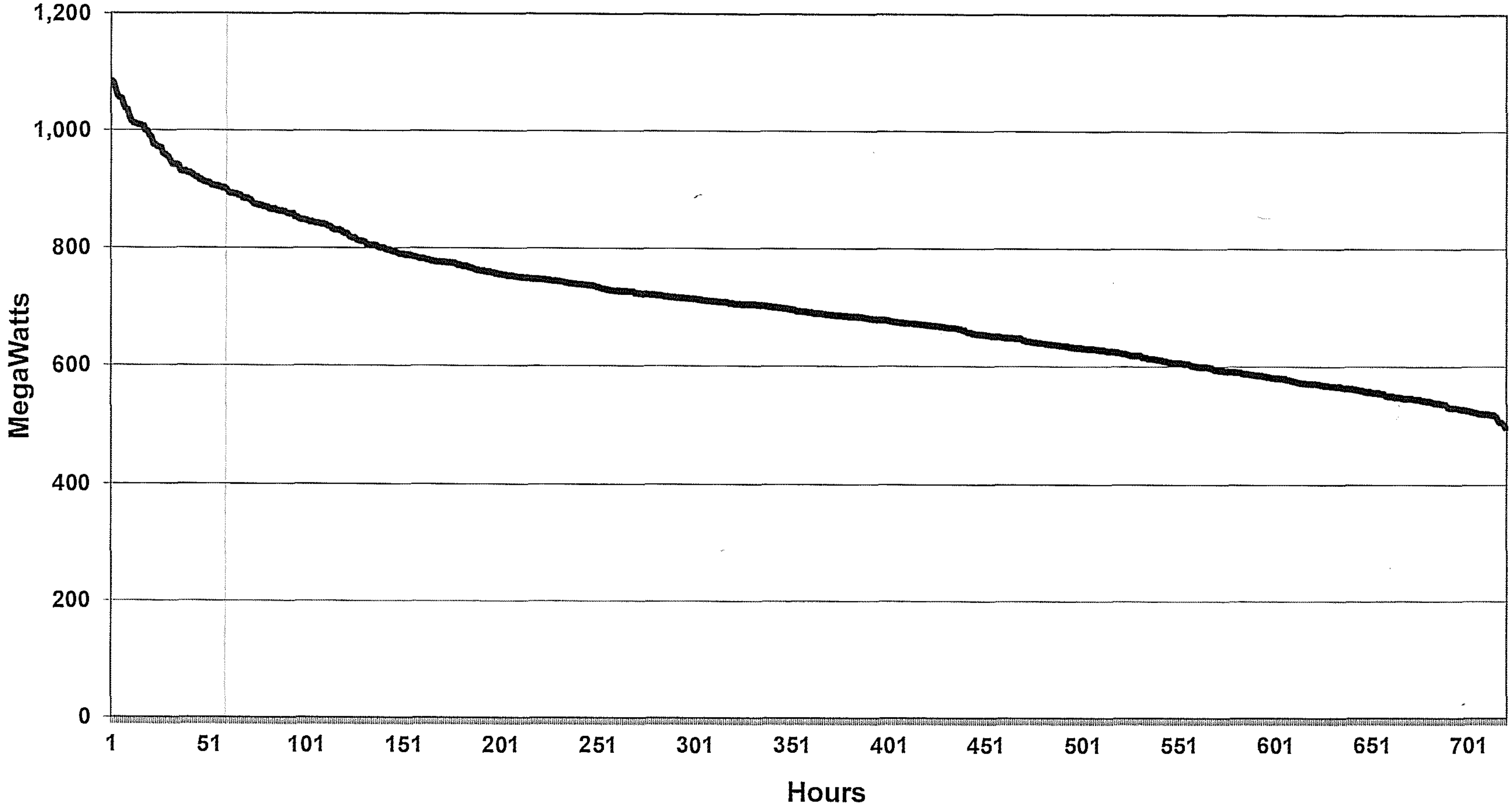
Kentucky Power Company
July 2013 Load Duration Curve
(Internal Load)



Kentucky Power Company
August 2013 Load Duration Curve
(Internal Load)



Kentucky Power Company
September 2013 Load Duration Curve
(Internal Load)



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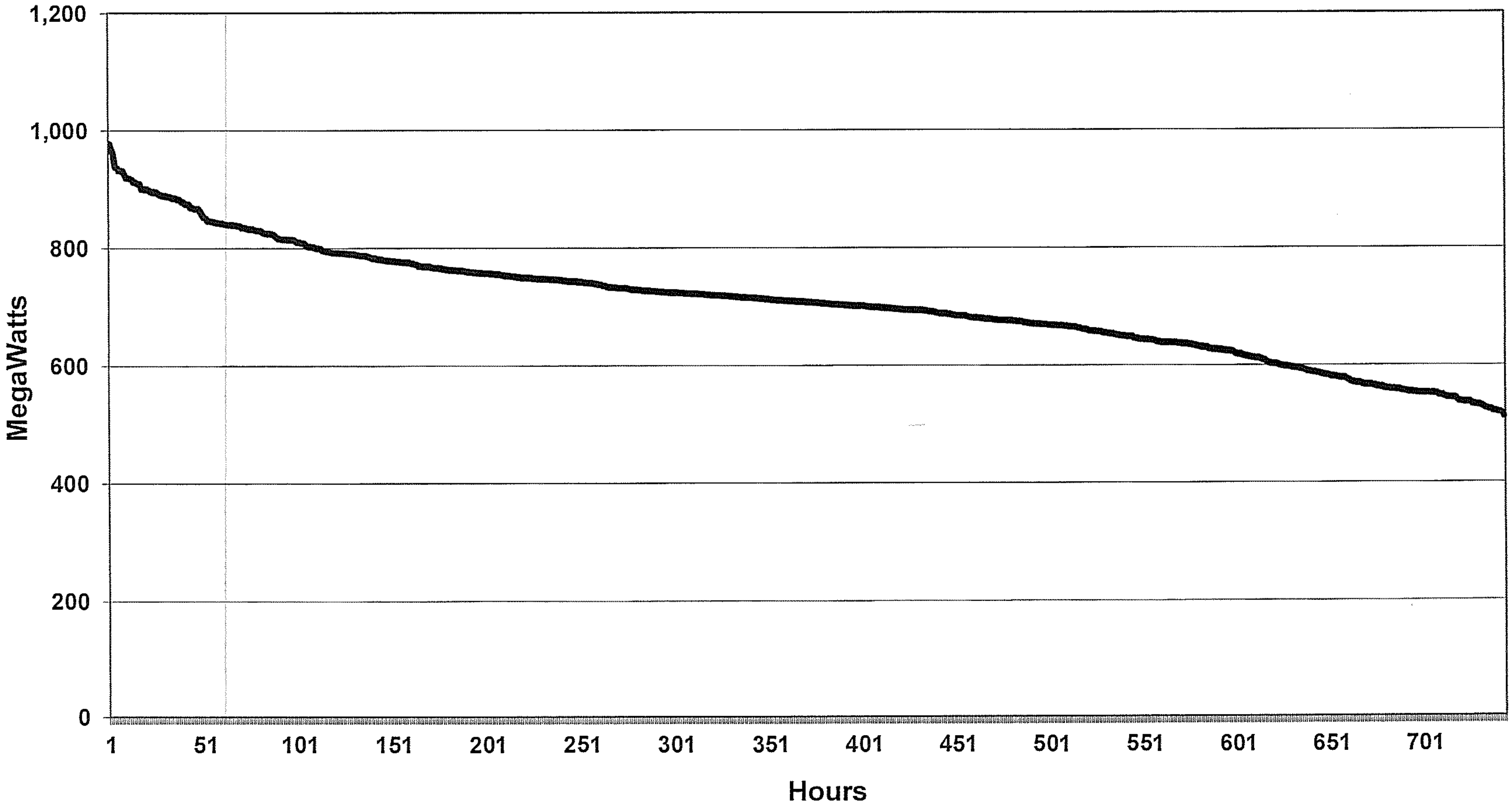
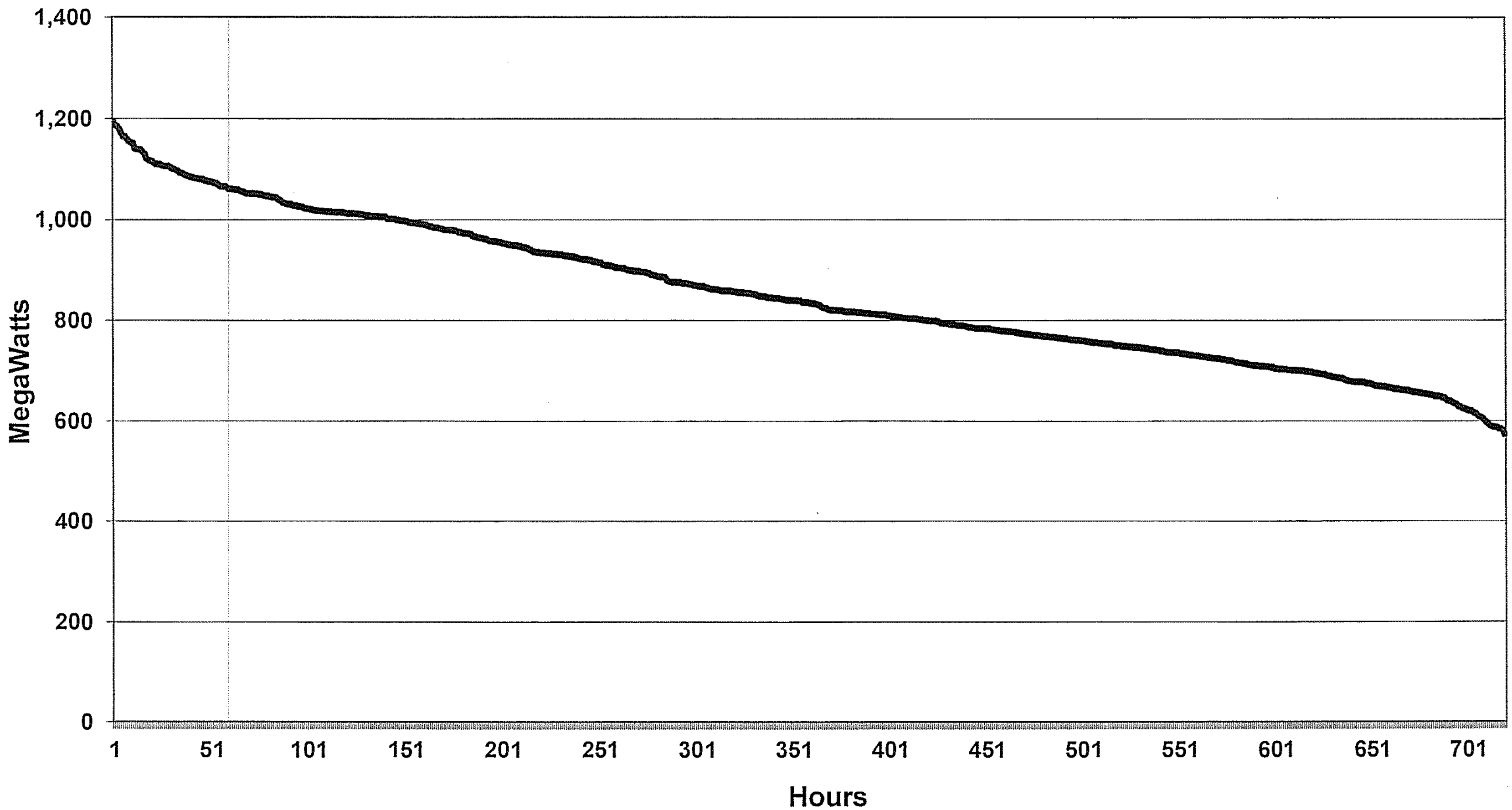
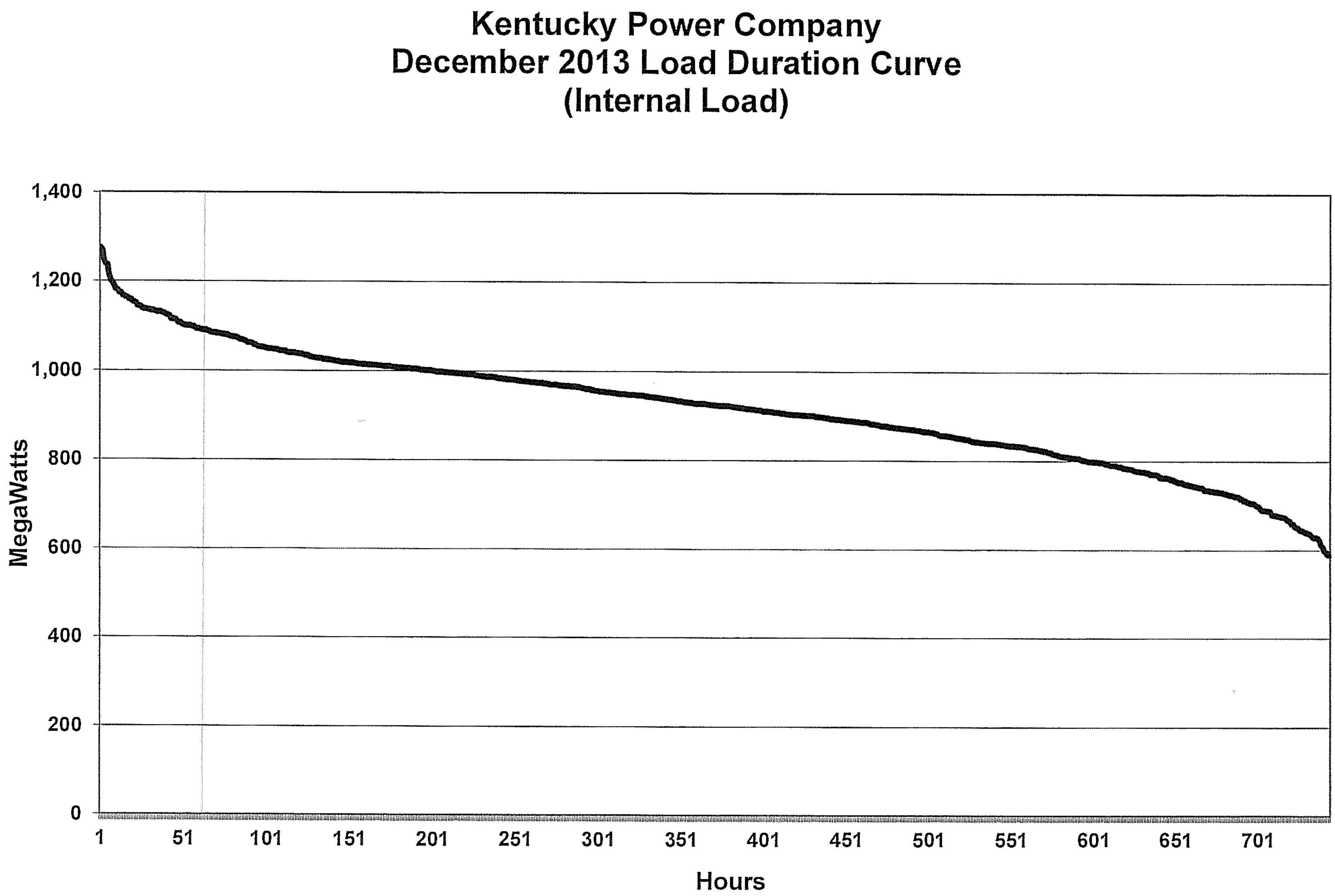
Kentucky Power Company
October 2013 Load Duration Curve
(Internal Load)



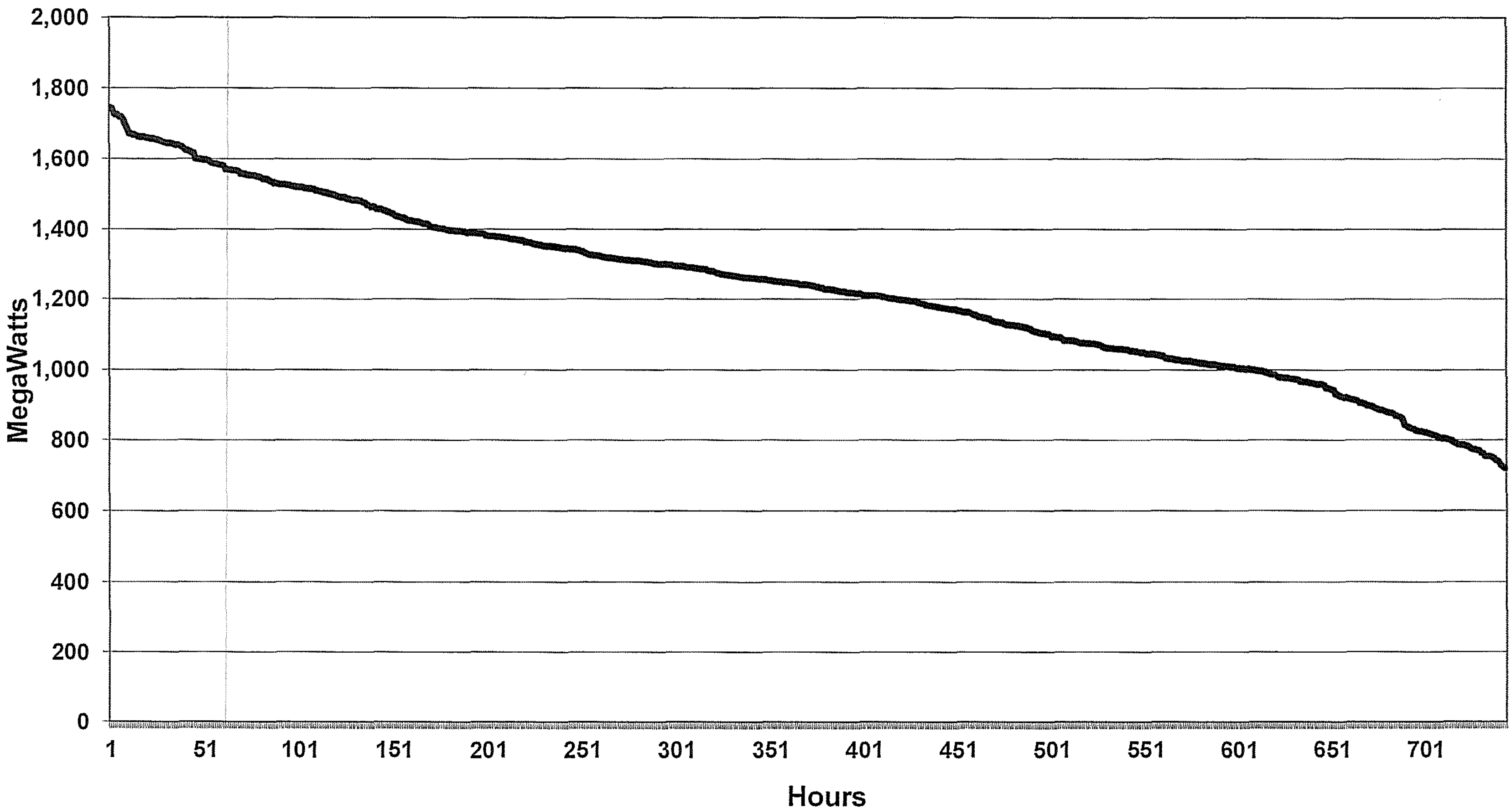
Kentucky Power Company
November 2013 Load Duration Curve
(Internal Load)



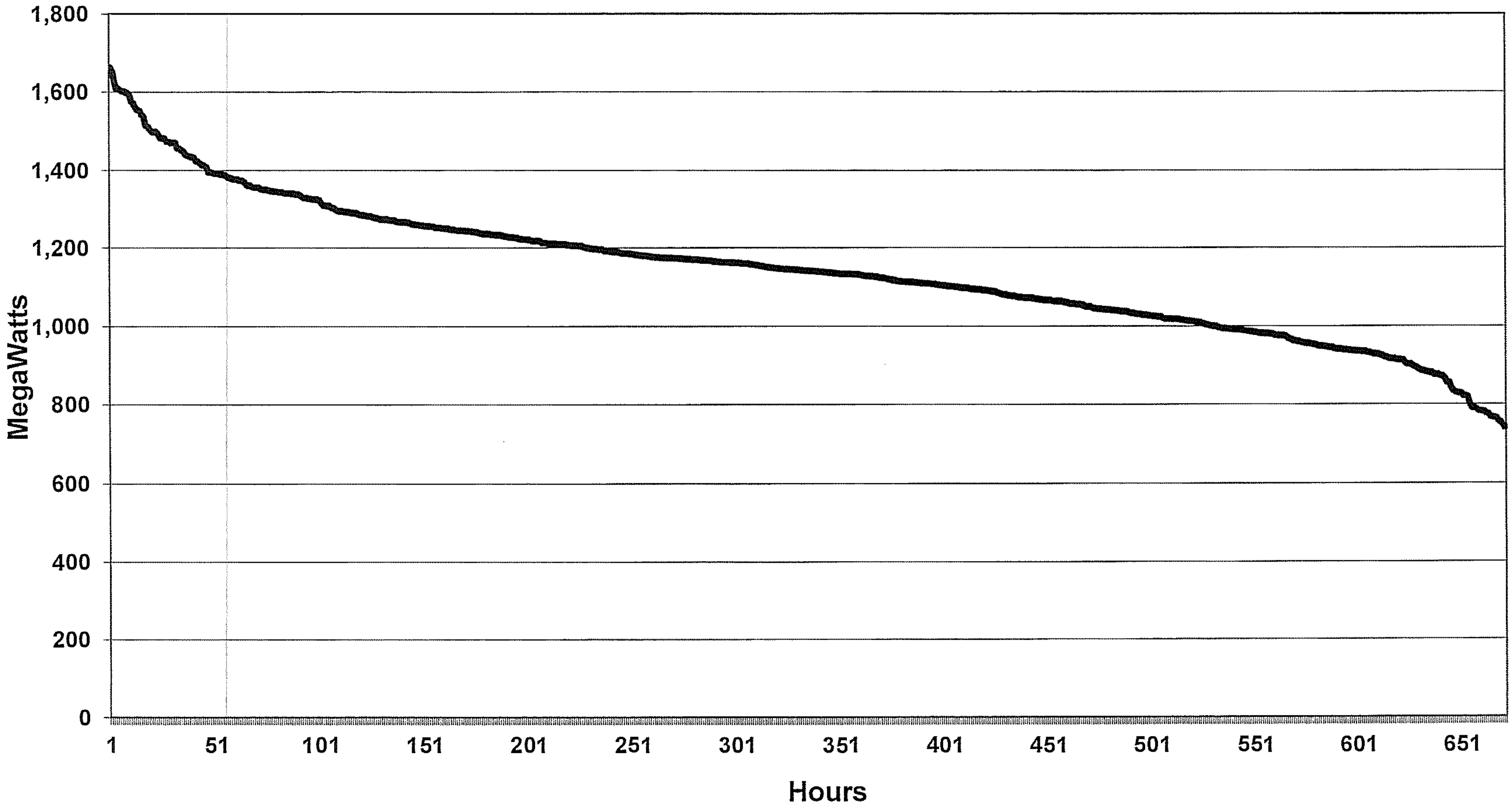


Kentucky Power Company
December 2013 Load Duration Curve
(Internal Load)
1,400
1,200
1,000
800
600
400
200
0
MegaWatts
1
51
101
151
201
251
301
351
401
451
501
551
601
651
701
Hours

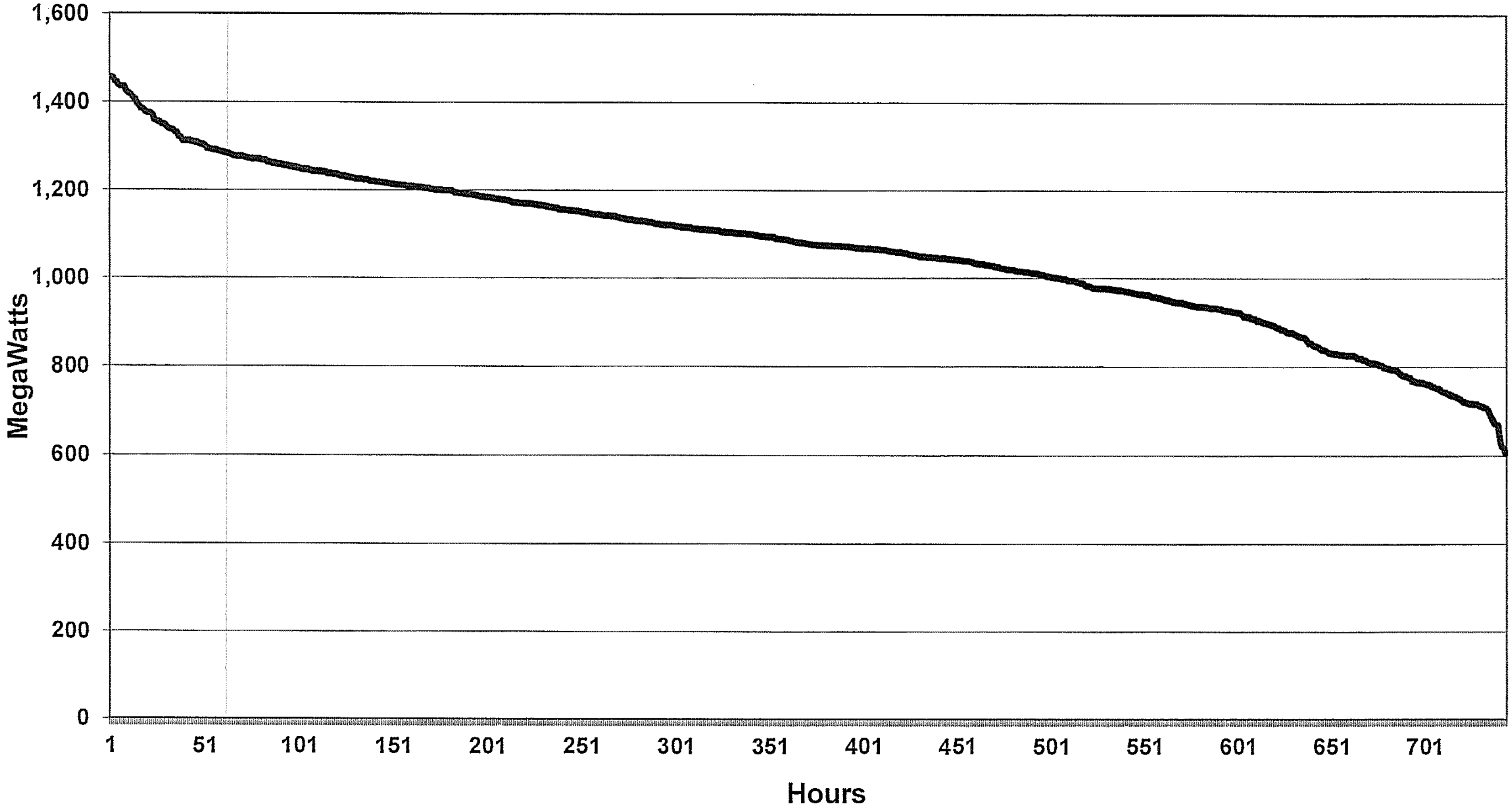
Kentucky Power Company
January 2013 Load Duration Curve
(System Load)



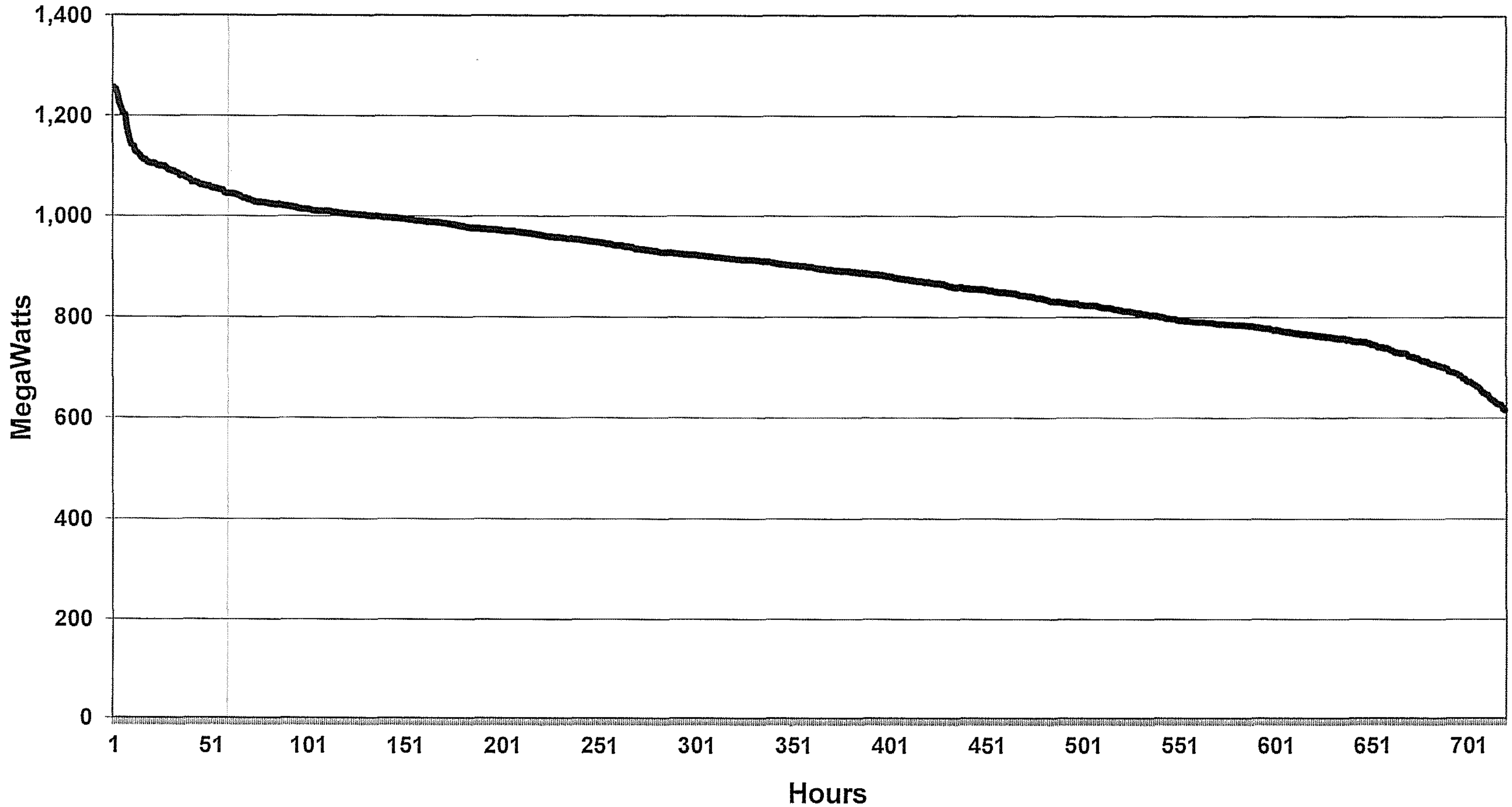
Kentucky Power Company
February 2013 Load Duration Curve
(System Load)



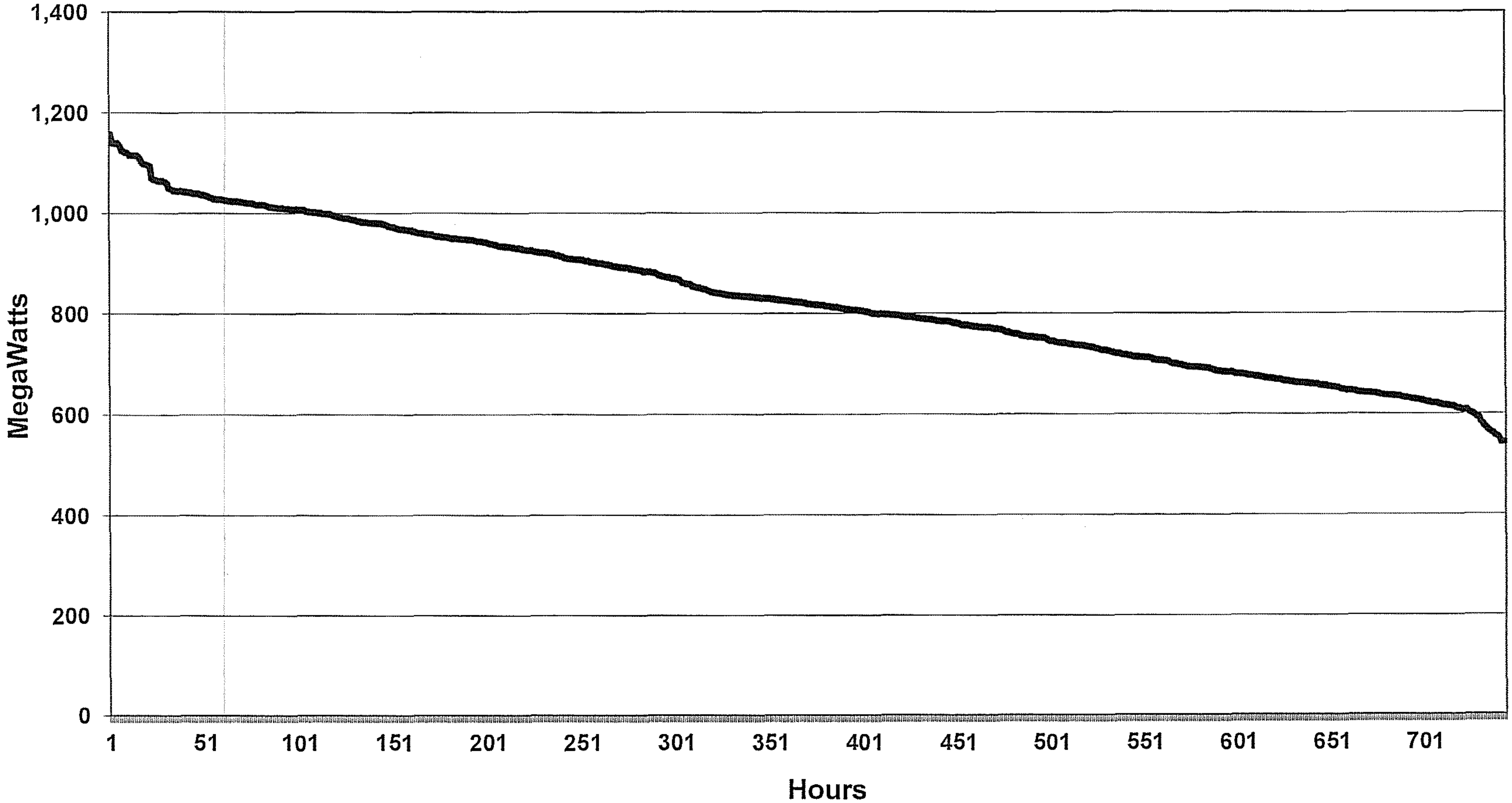
Kentucky Power Company
March 2013 Load Duration Curve
(System Load)



Kentucky Power Company
April 2013 Load Duration Curve
(System Load)



Kentucky Power Company
May 2013 Load Duration Curve
(System Load)



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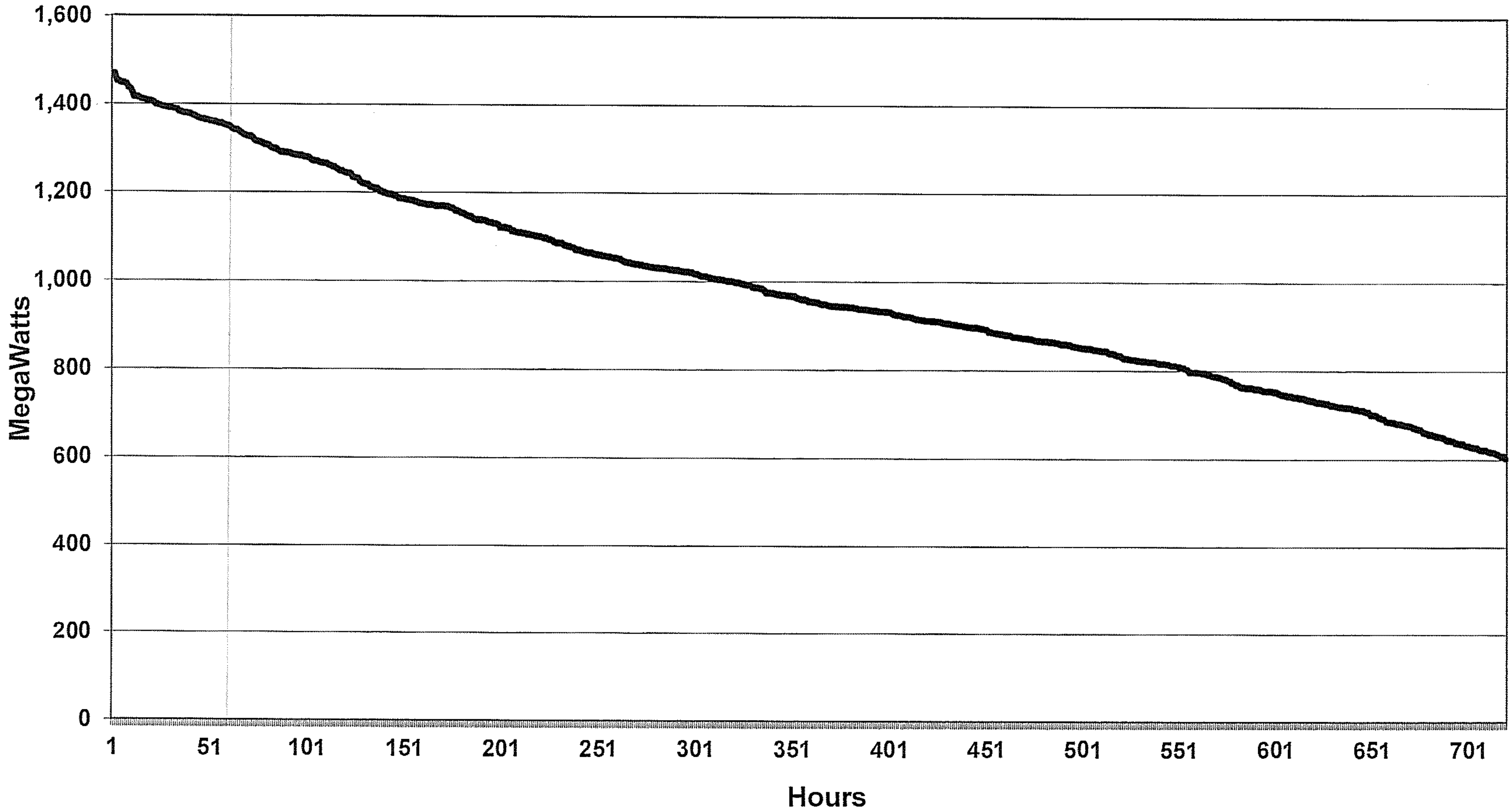
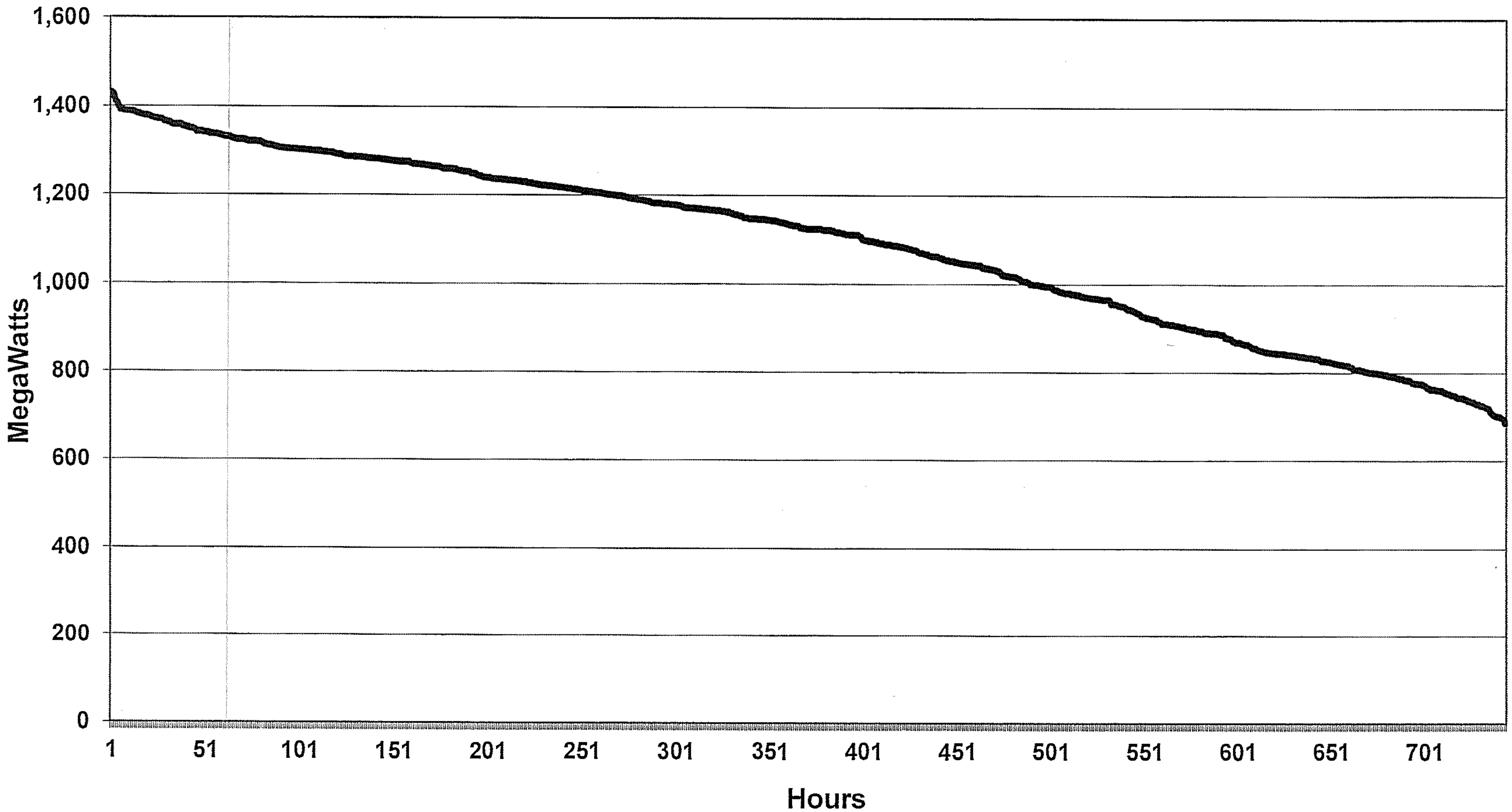
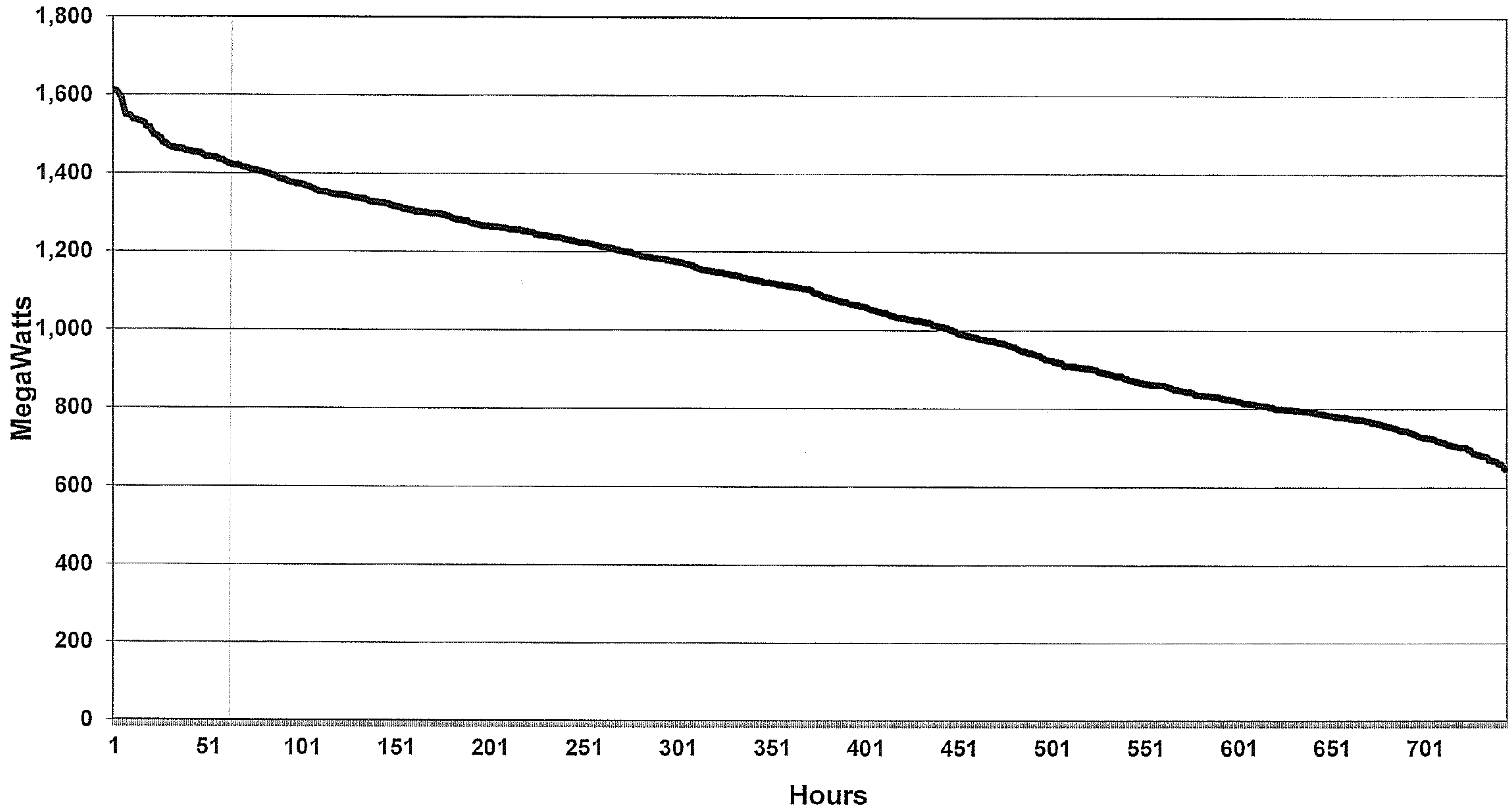
Kentucky Power Company
June 2013 Load Duration Curve
(System Load)



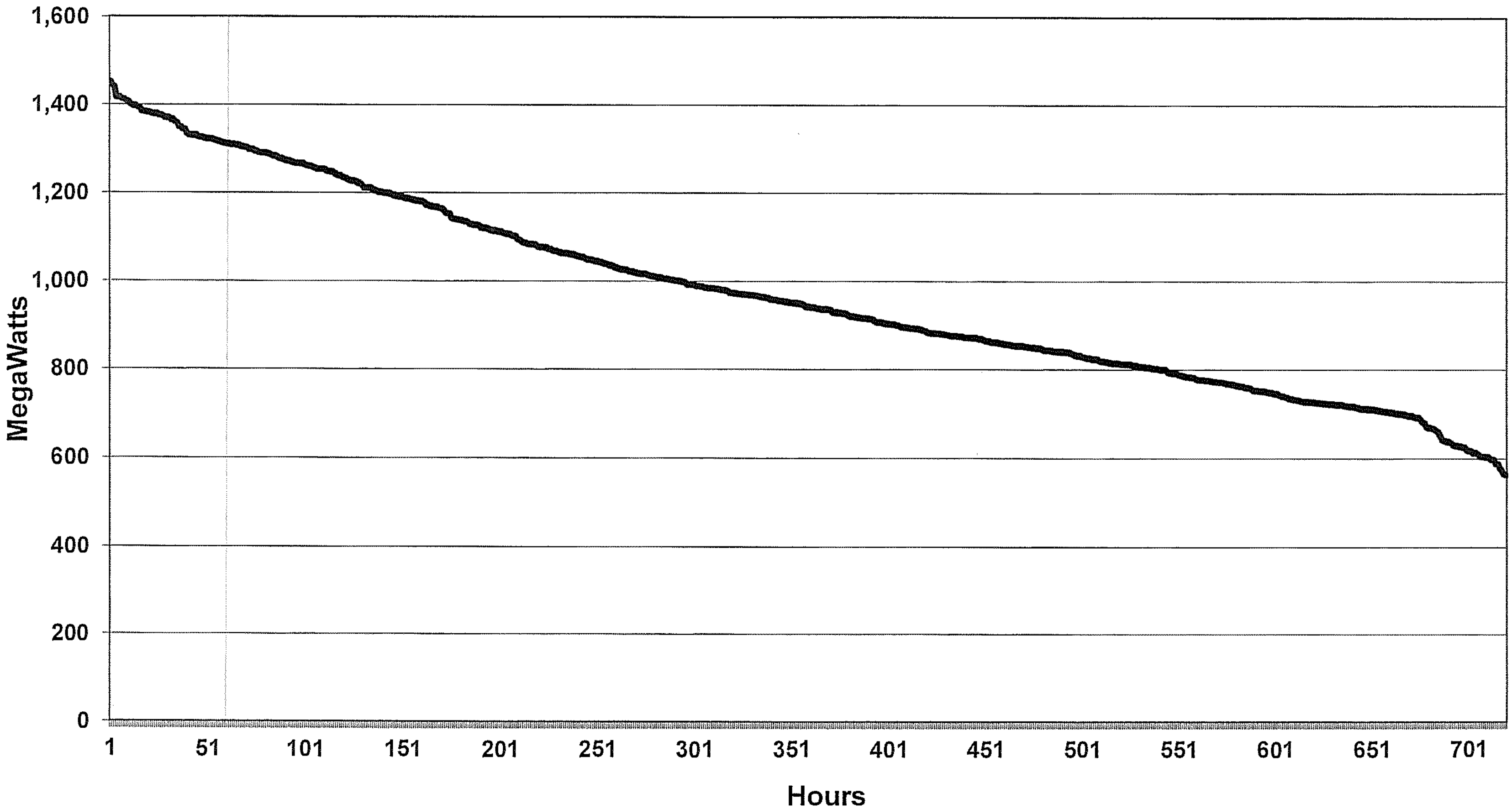
Kentucky Power Company
July 2013 Load Duration Curve
(System Load)



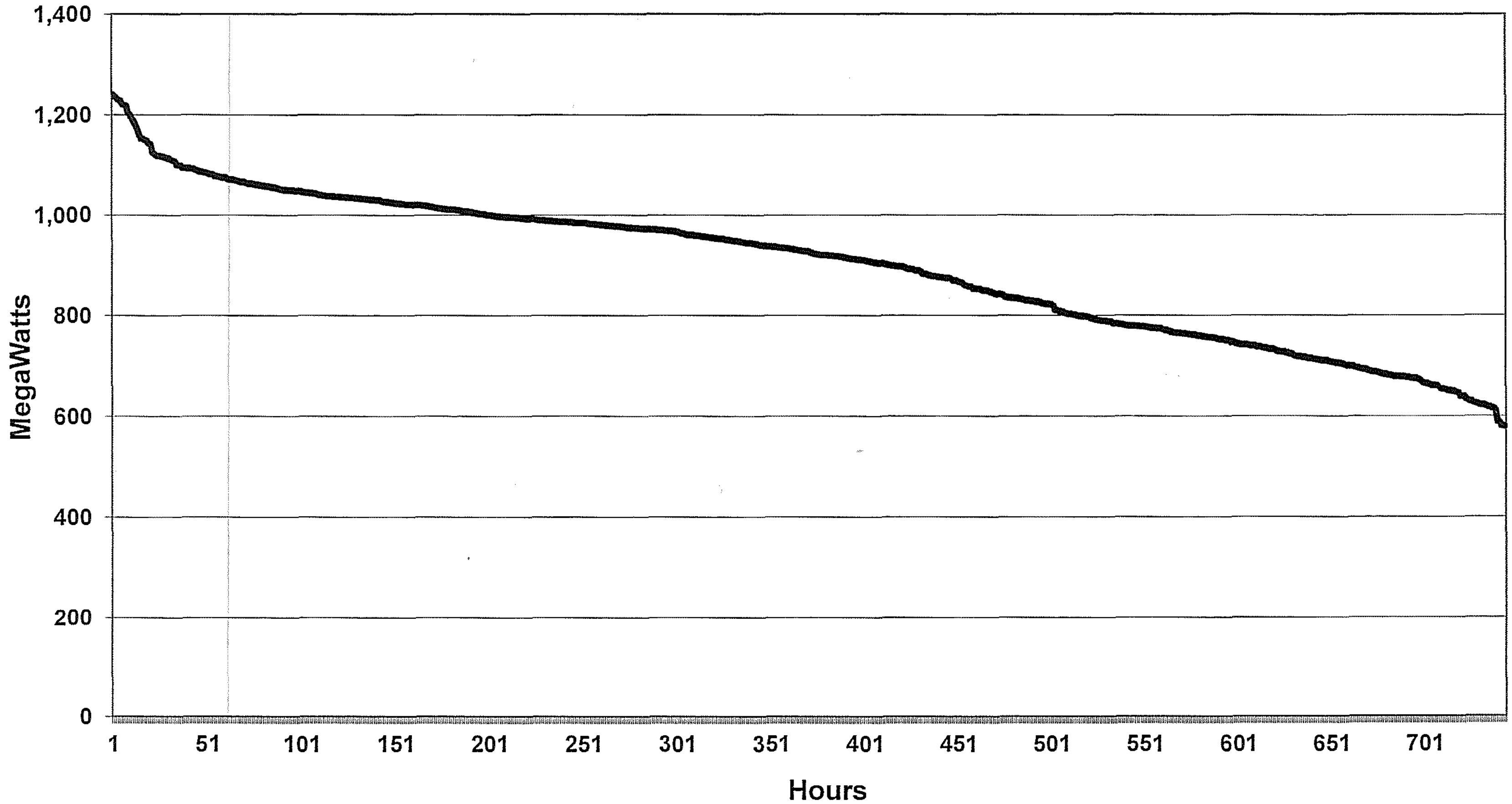
Kentucky Power Company
August 2013 Load Duration Curve
(System Load)



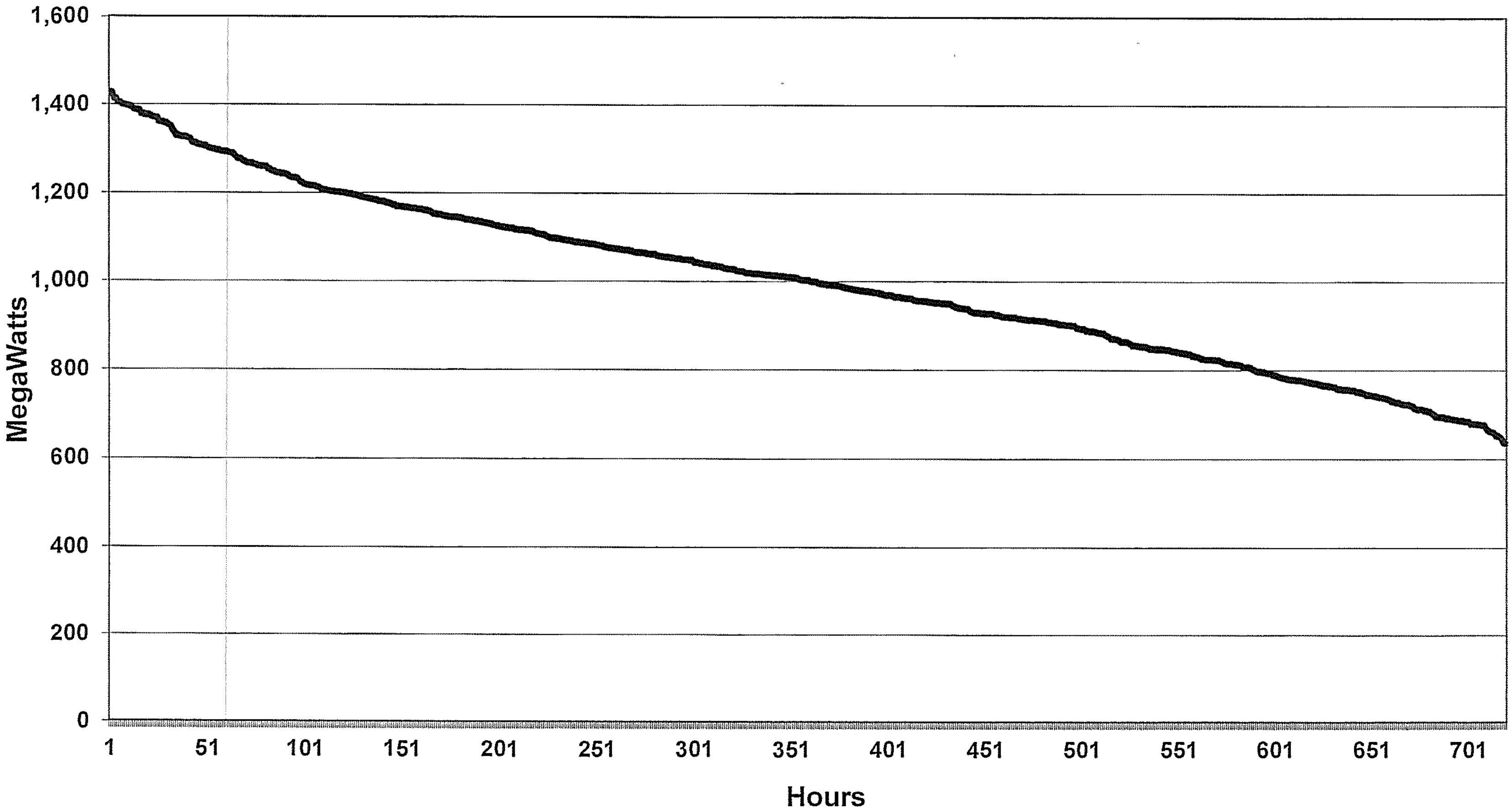
Kentucky Power Company
September 2013 Load Duration Curve
(System Load)



Kentucky Power Company
October 2013 Load Duration Curve
(System Load)



Kentucky Power Company
November 2013 Load Duration Curve
(System Load)



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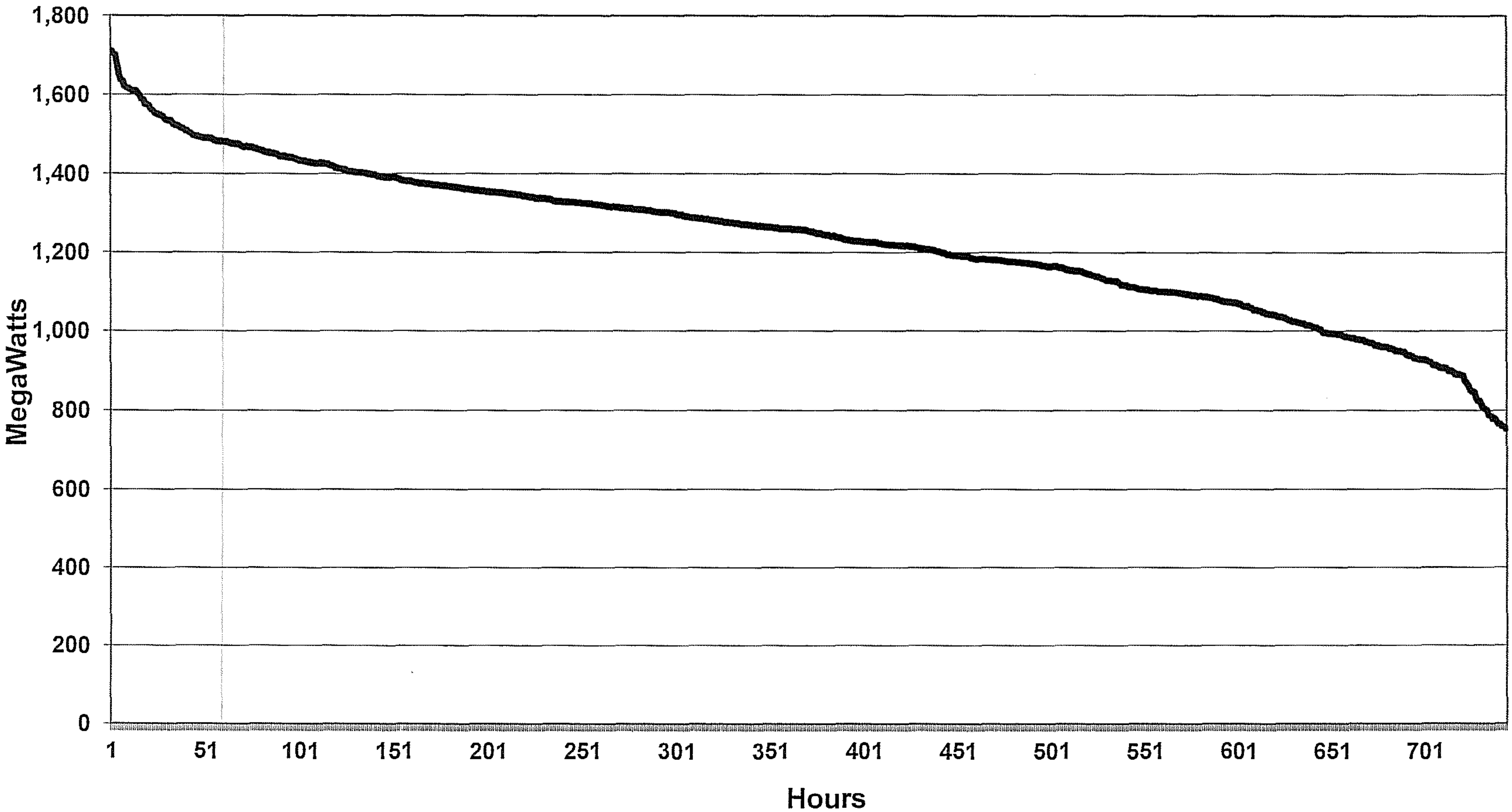
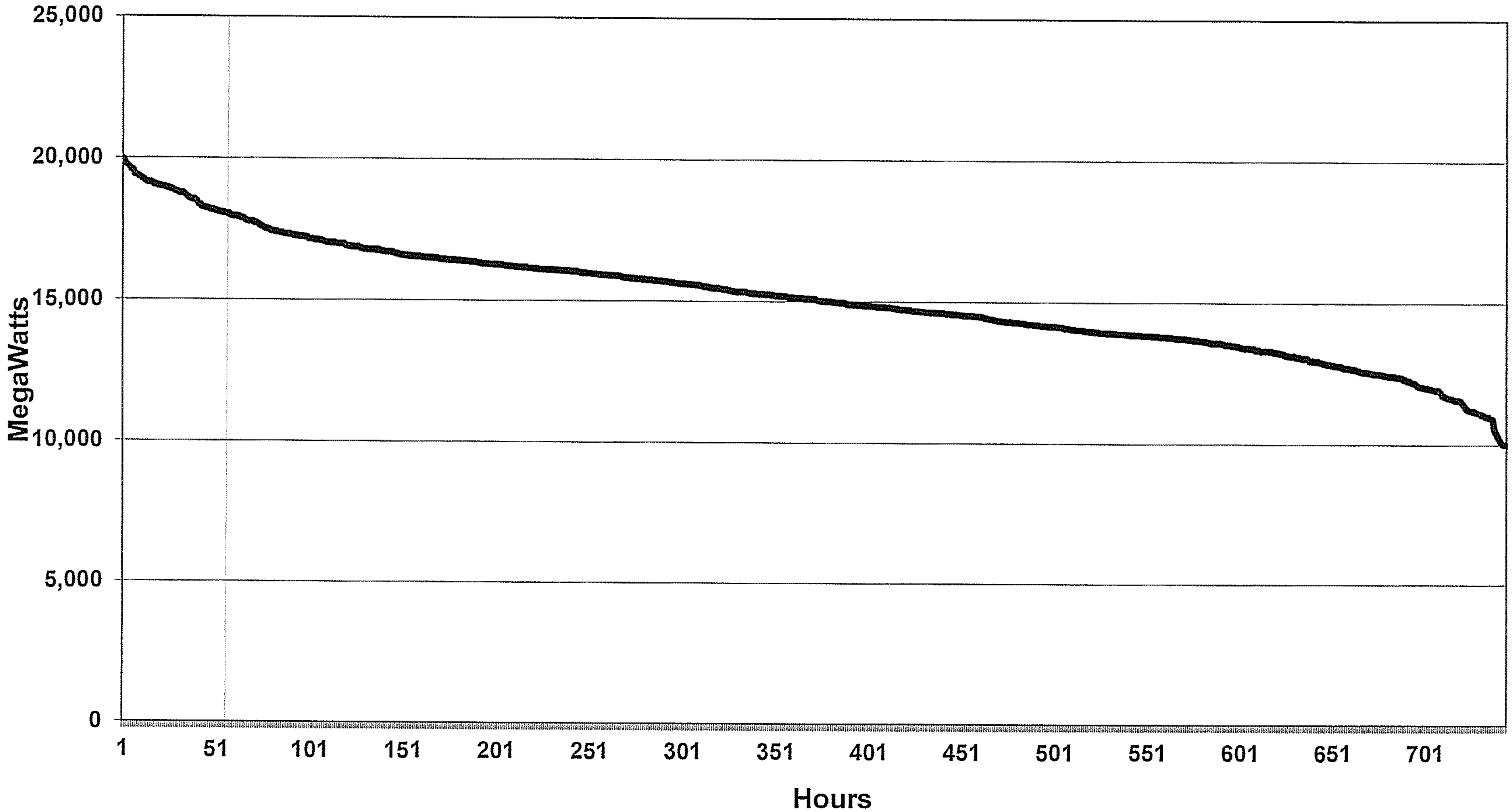
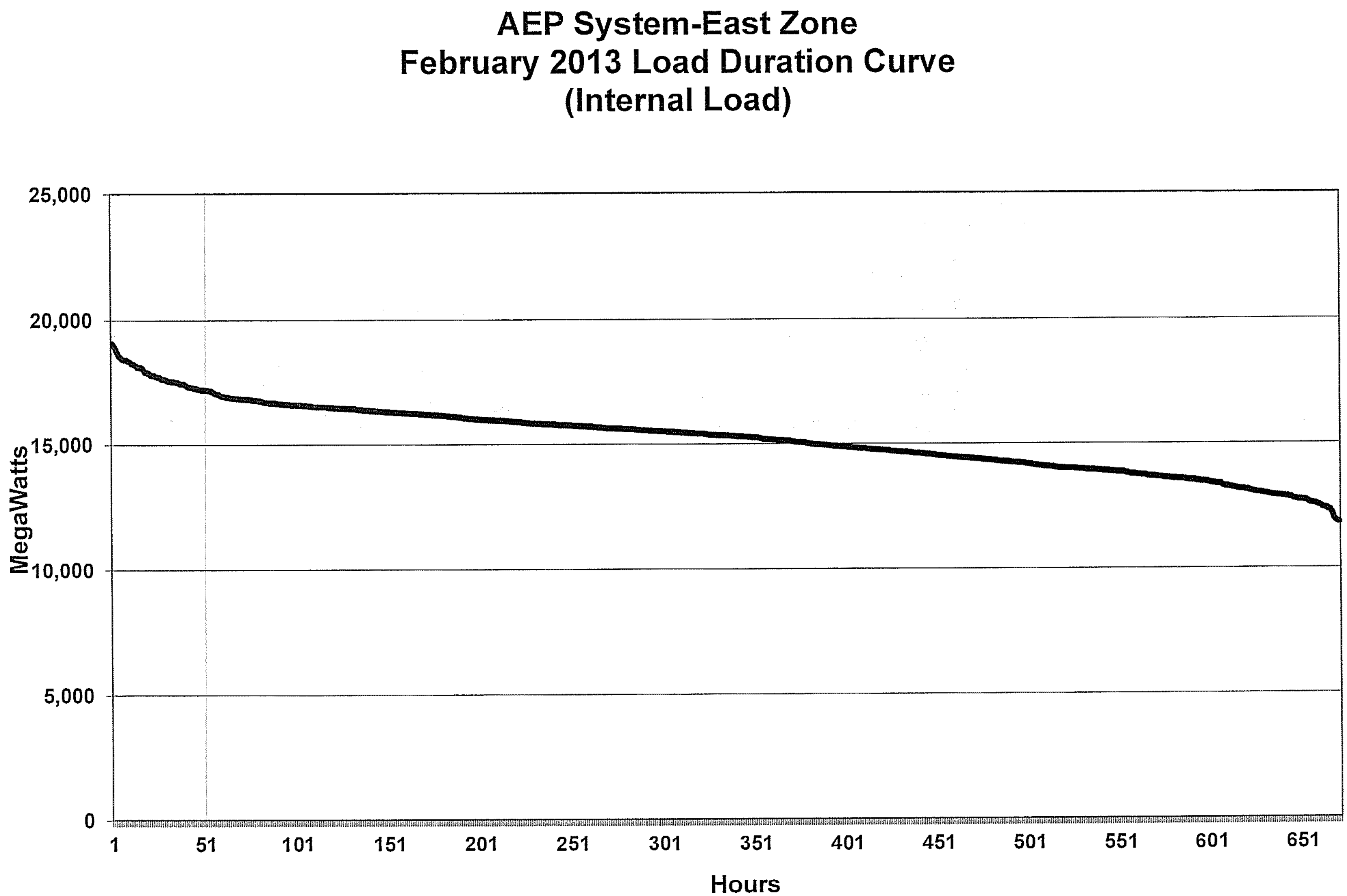
Kentucky Power Company
December 2013 Load Duration Curve
(System Load)



AEP System-East Zone
January 2013 Load Duration Curve
(Internal Load)





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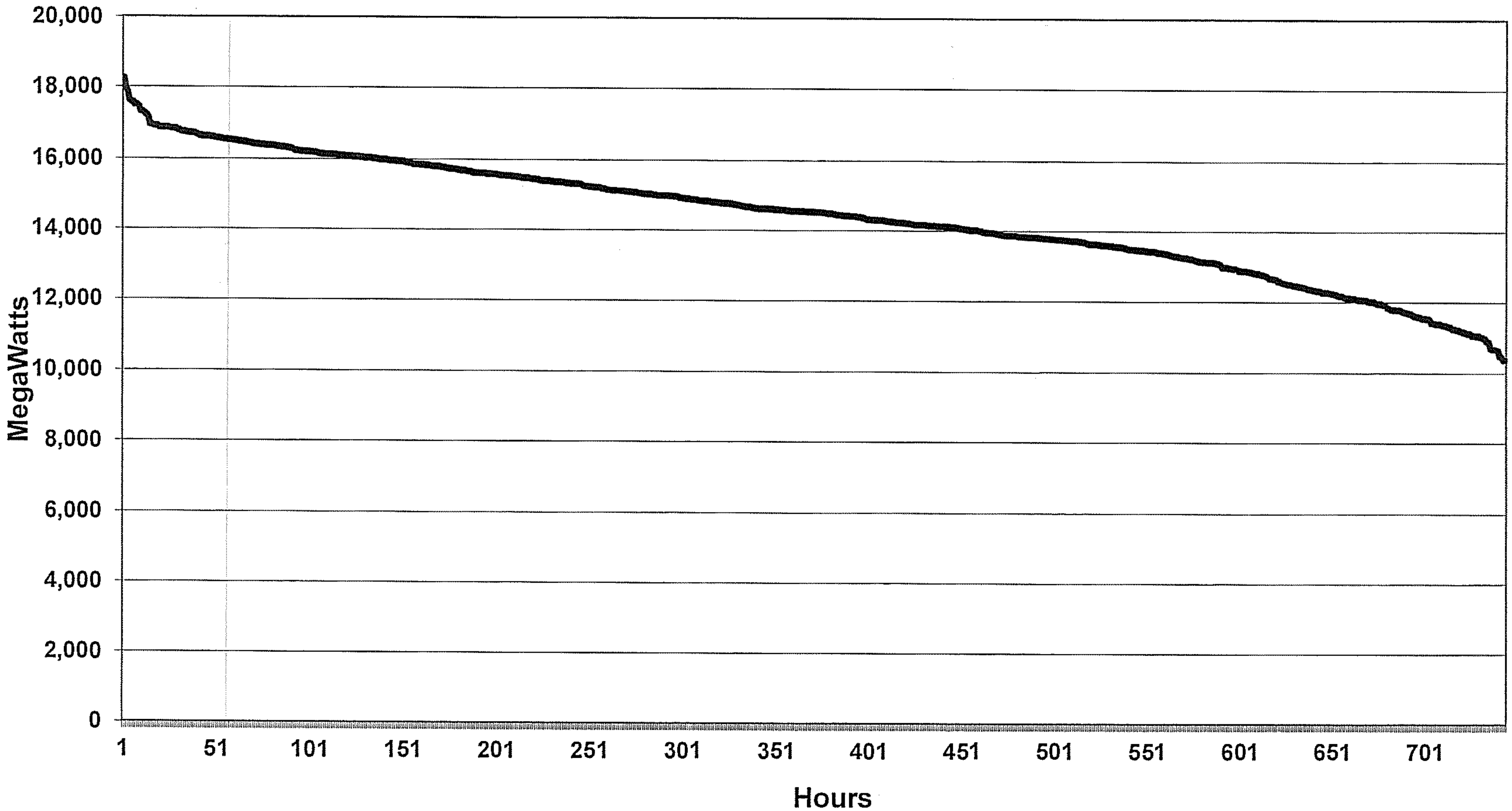
AEP System-East Zone
March 2013 Load Duration Curve
(Internal Load)



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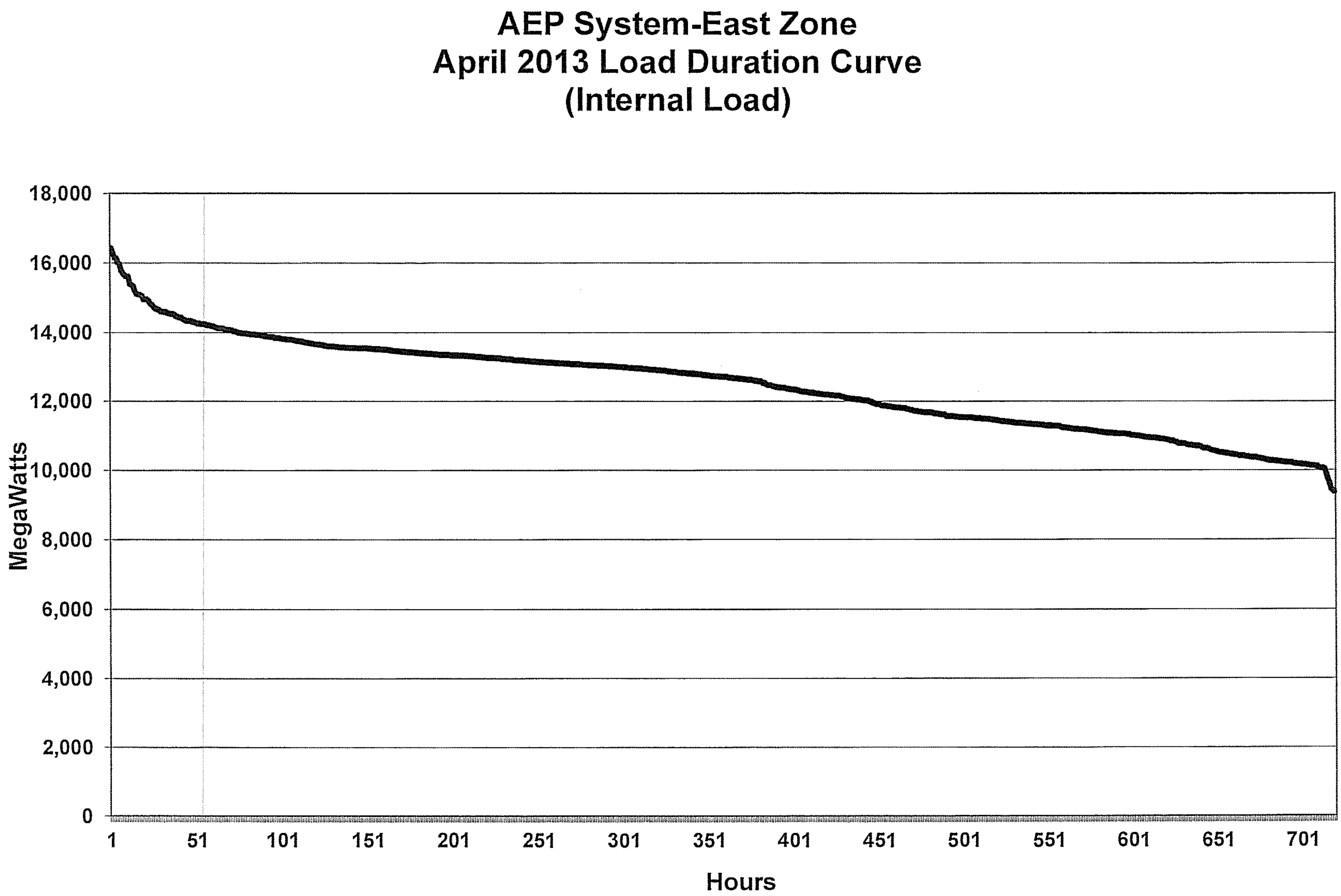
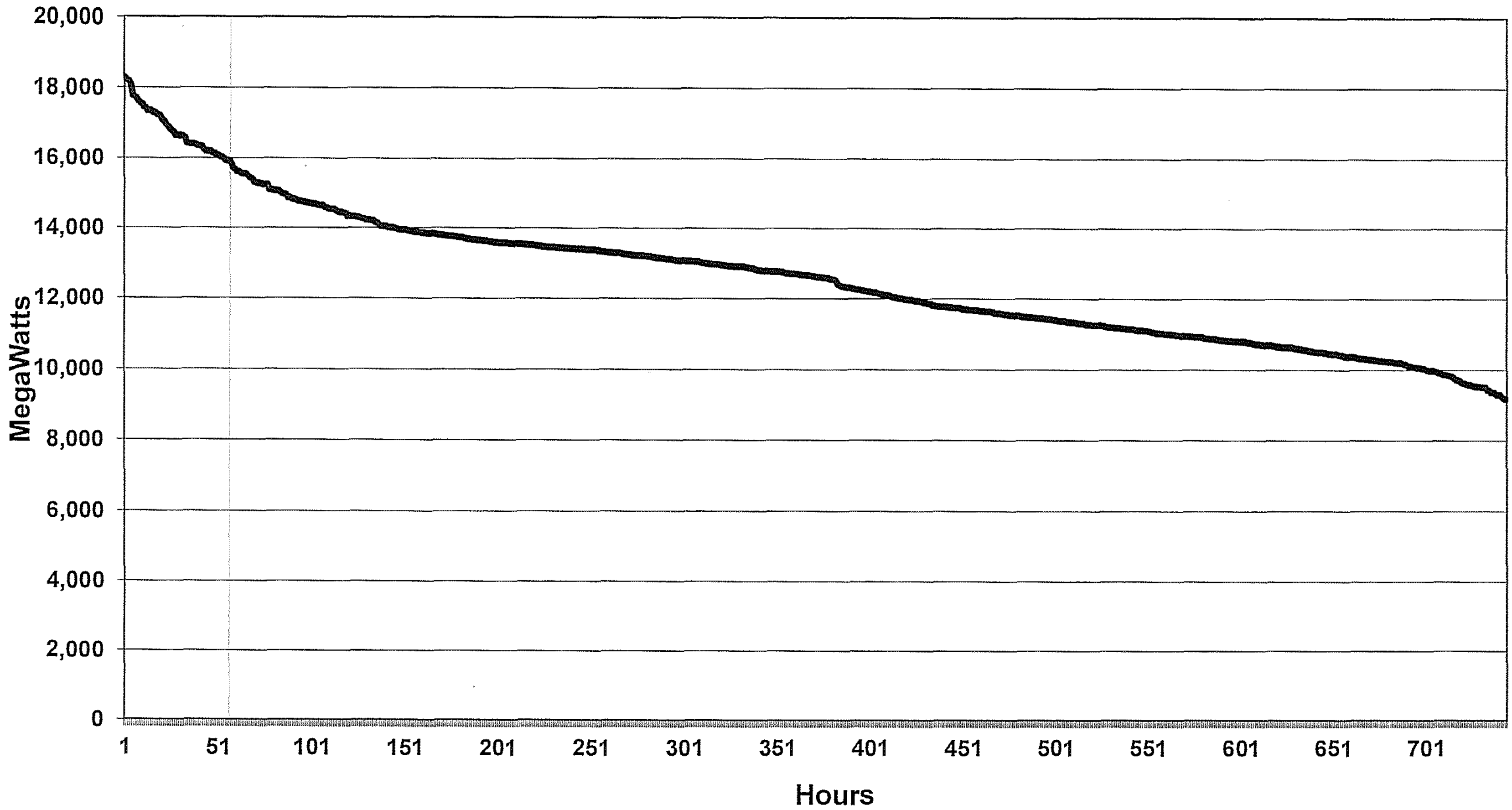
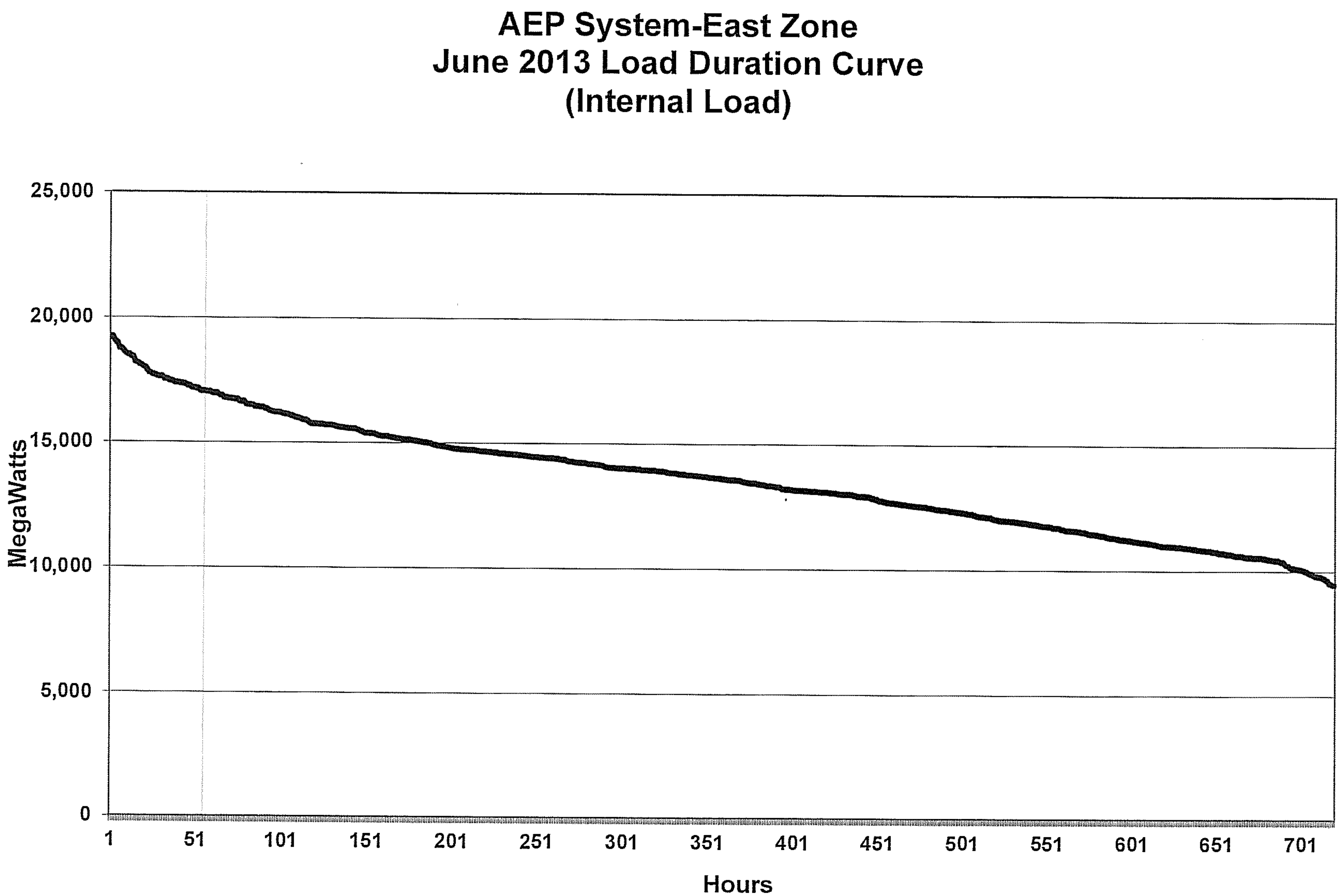
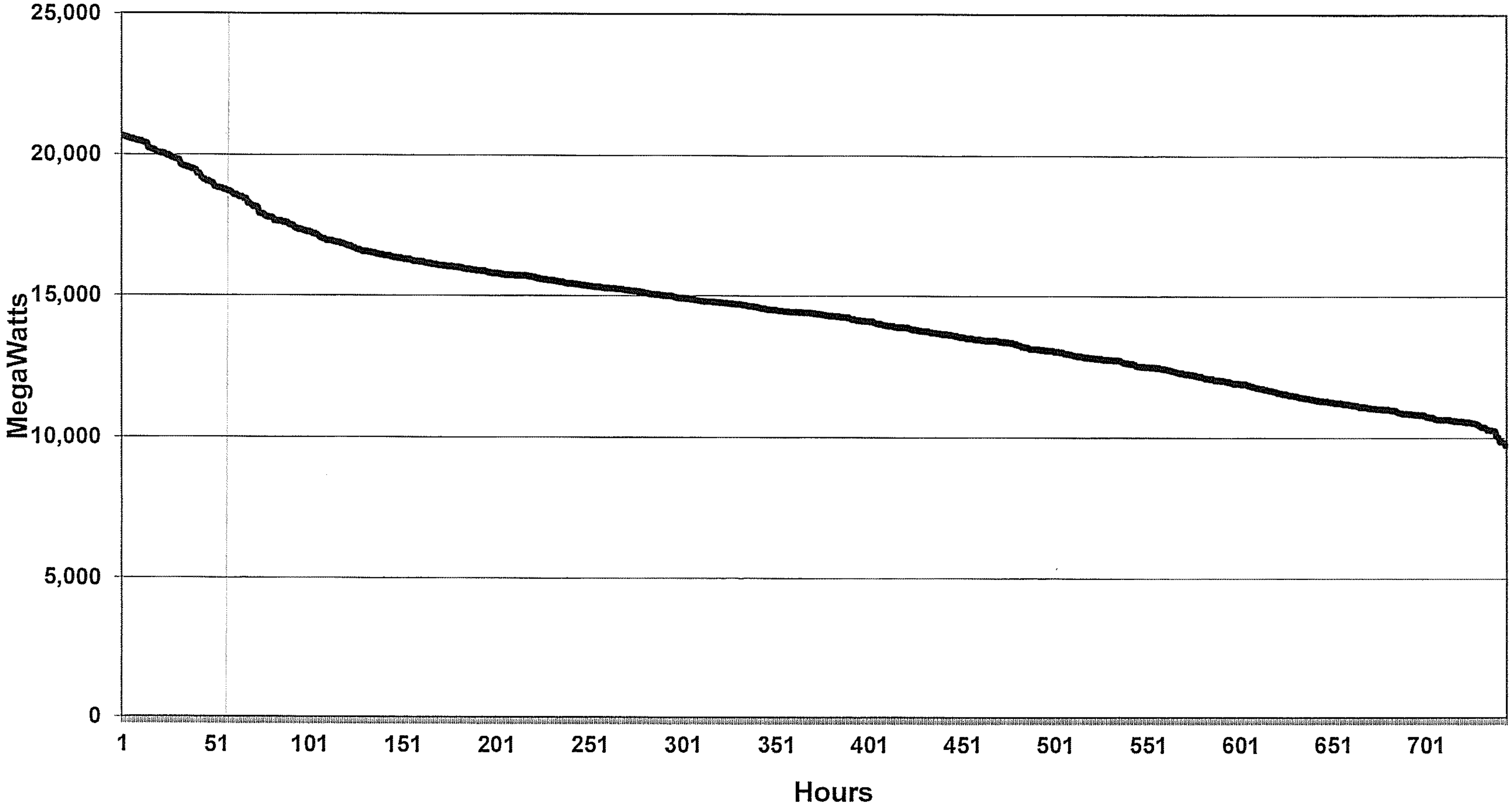

AEP System-East Zone
April 2013 Load Duration Curve
(Internal Load)
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
MegaWatts
1
51
101
151
201
251
301
351
401
451
501
551
601
651
701
Hours

AEP System-East Zone
May 2013 Load Duration Curve
(Internal Load)

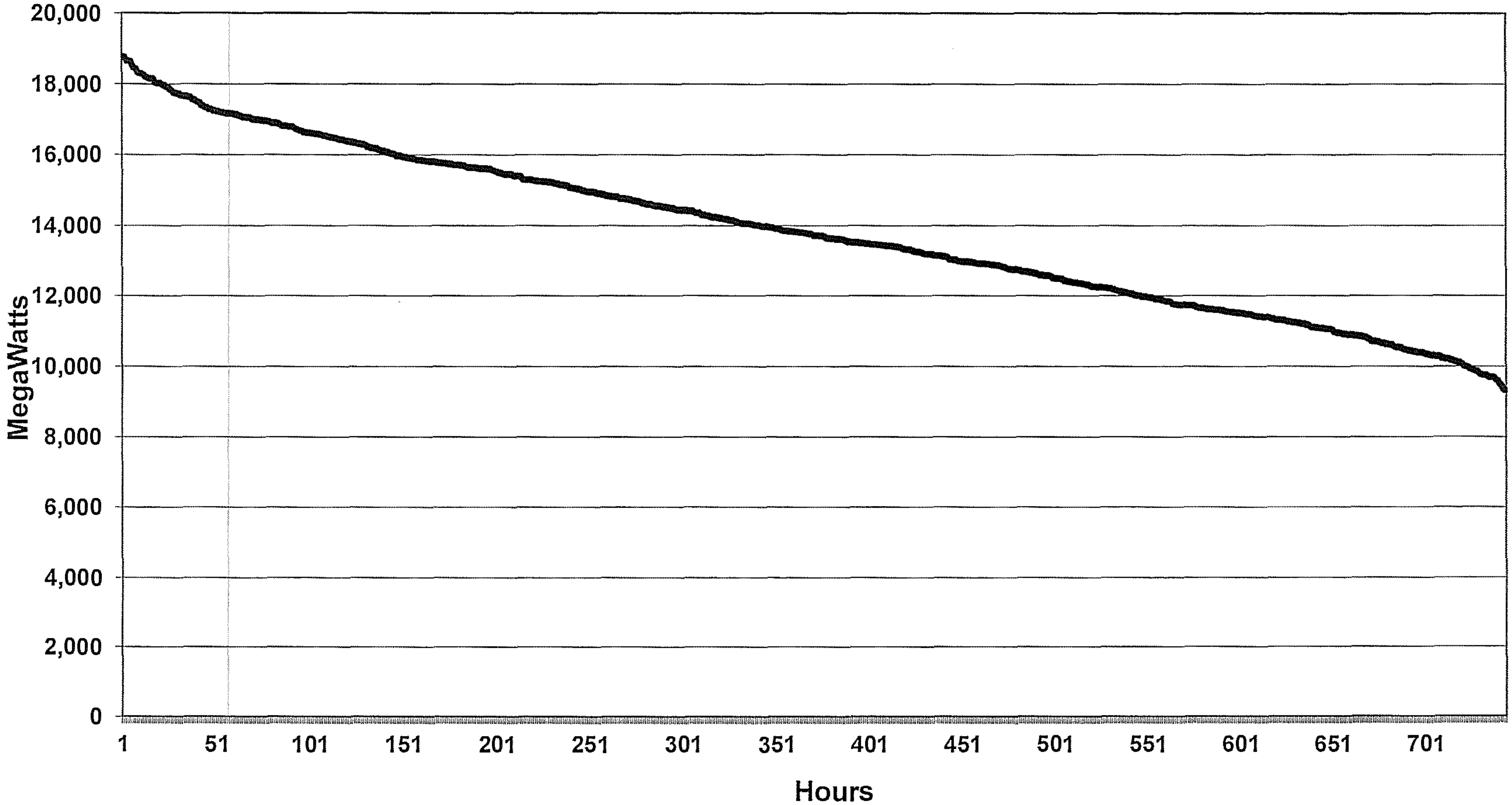



AEP System-East Zone
June 2013 Load Duration Curve
(Internal Load)
25,000
20,000
15,000
10,000
5,000
0
MegaWatts
1
51
101
151
201
251
301
351
401
451
501
551
601
651
701
Hours

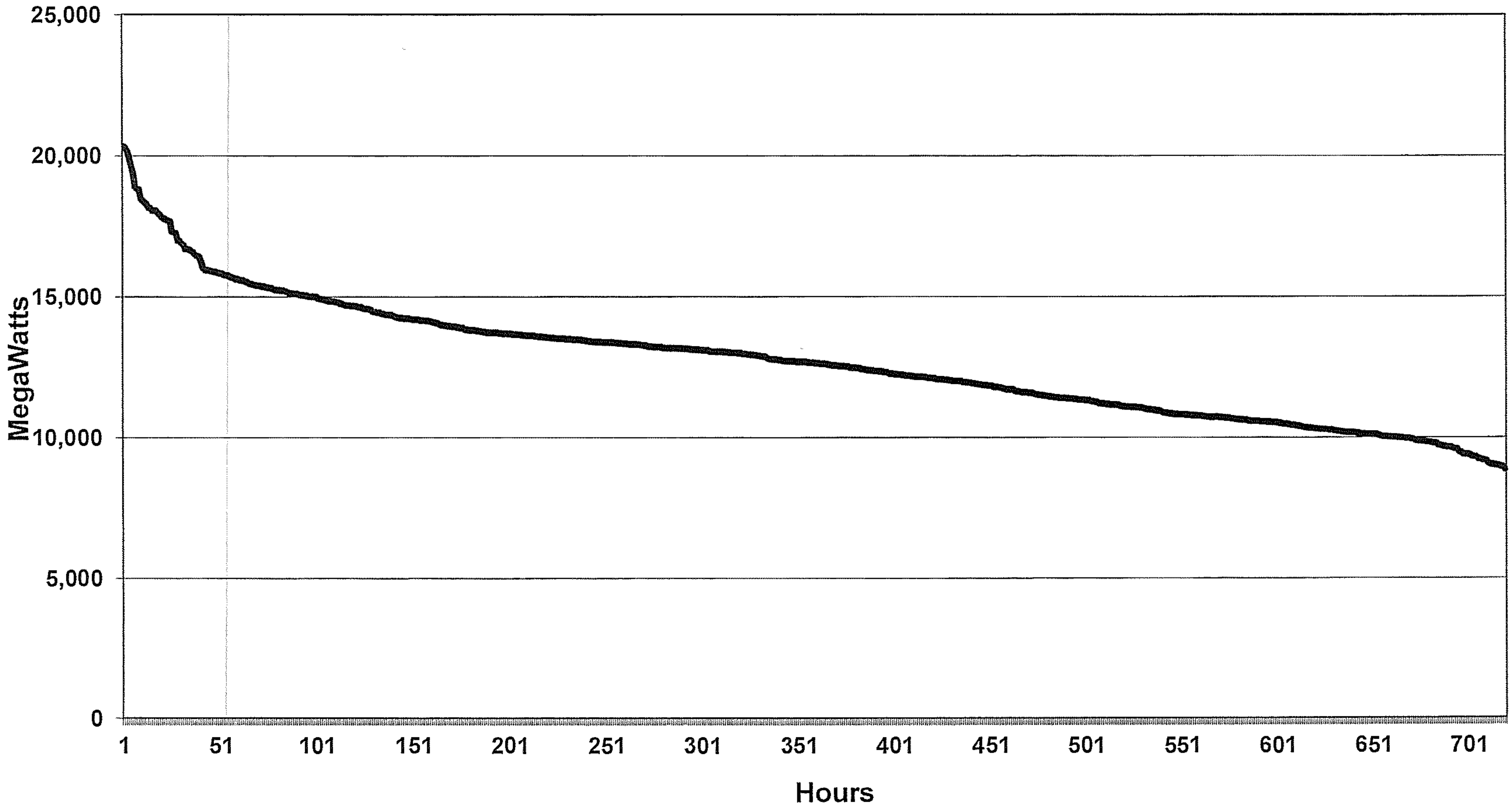
AEP System-East Zone
July 2013 Load Duration Curve
(Internal Load)



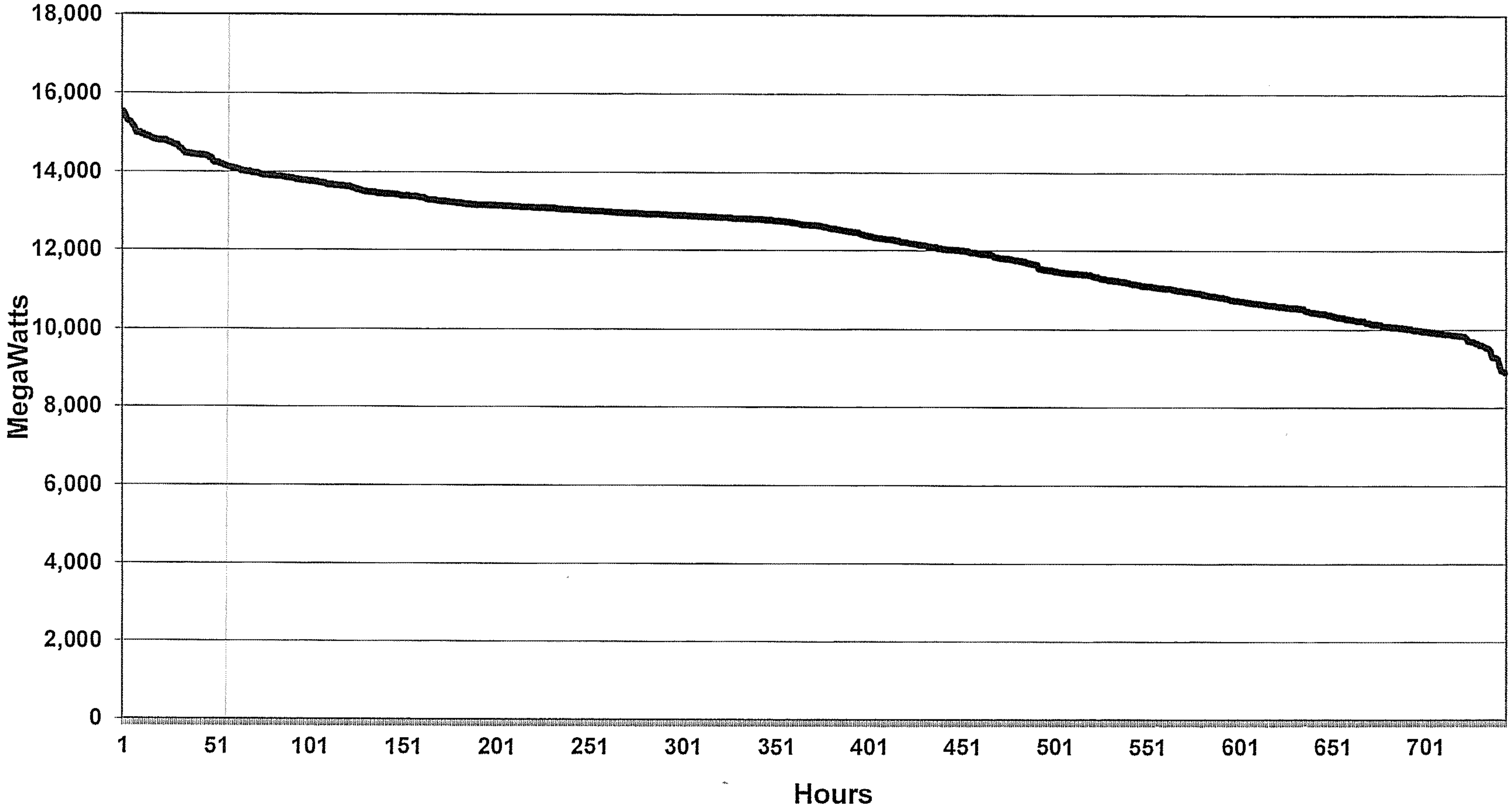
AEP System-East Zone
August 2013 Load Duration Curve
(Internal Load)

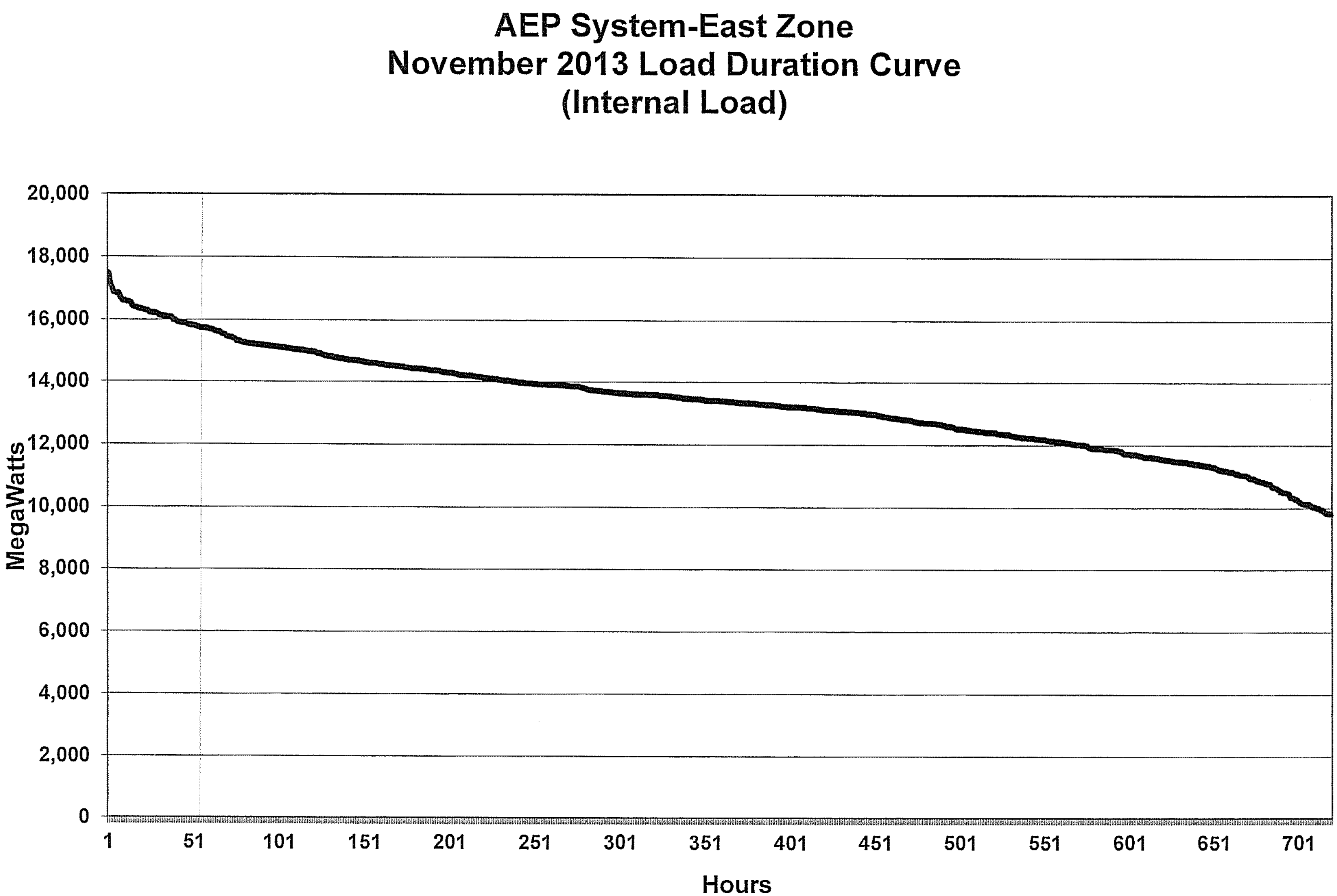


AEP System-East Zone
September 2013 Load Duration Curve
(Internal Load)

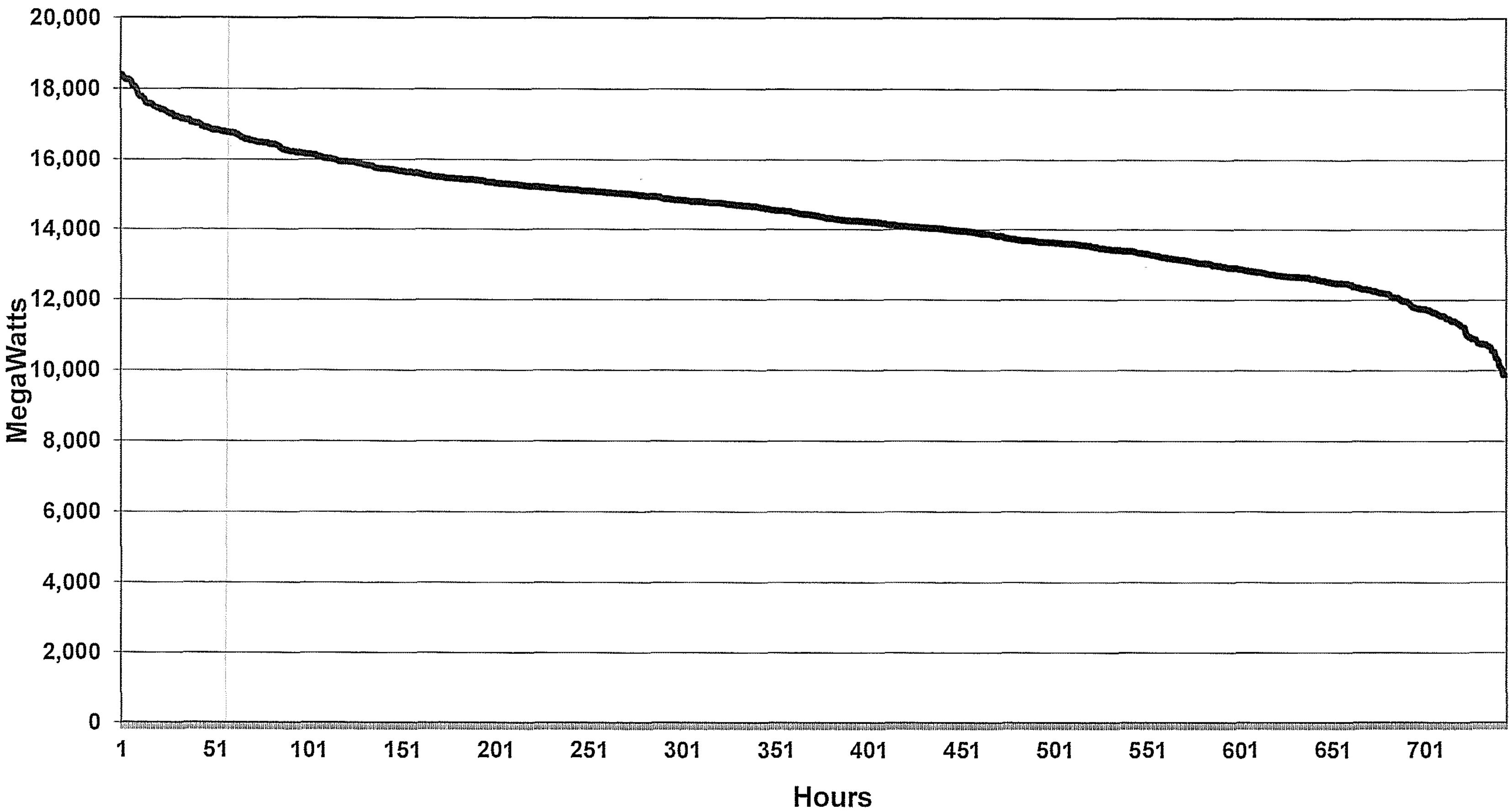


AEP System-East Zone
October 2013 Load Duration Curve
(Internal Load)

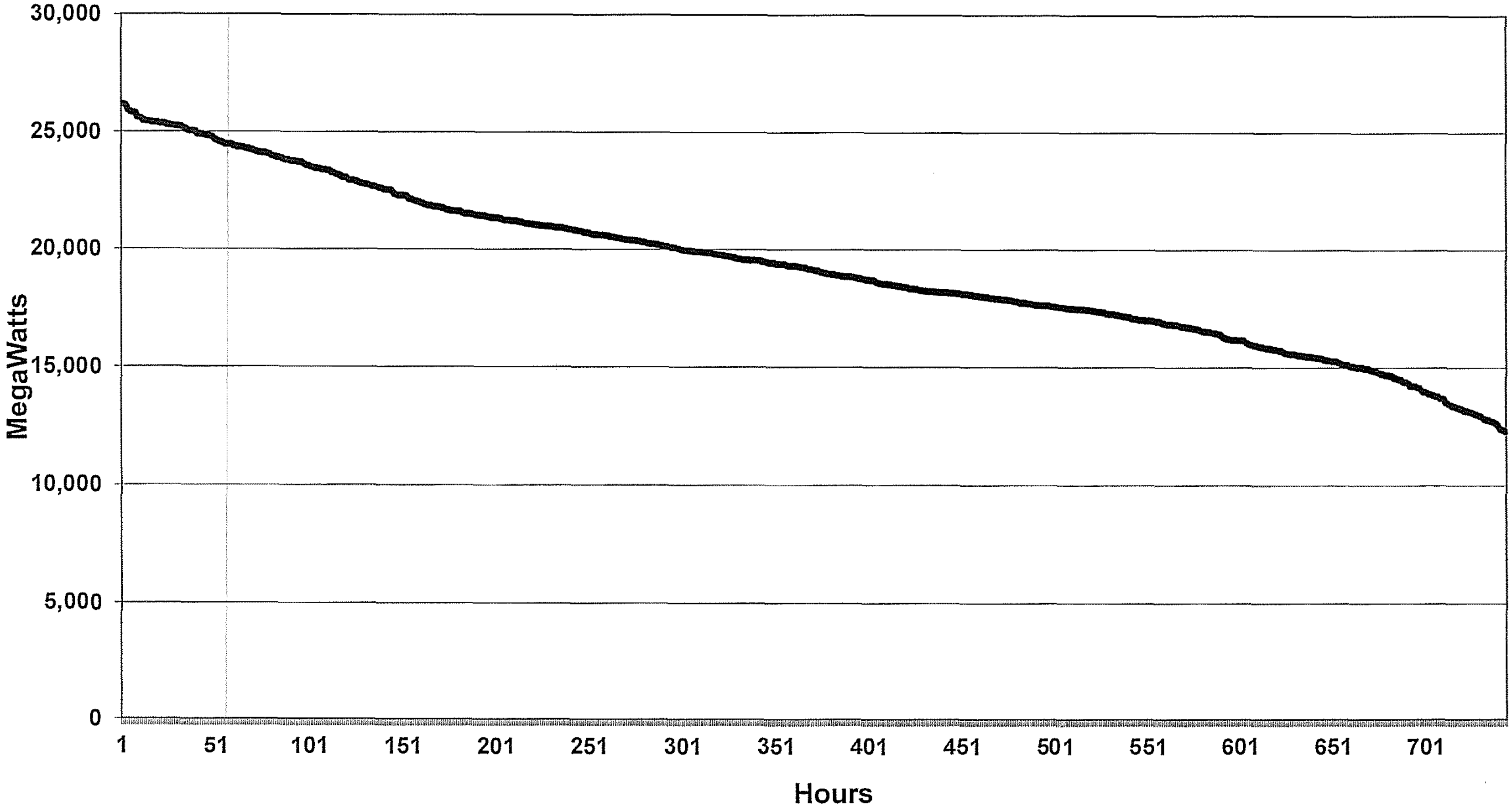



AEP System-East Zone
November 2013 Load Duration Curve
(Internal Load)
20,000
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
MegaWatts
1
51
101
151
201
251
301
351
401
451
501
551
601
651
701
Hours

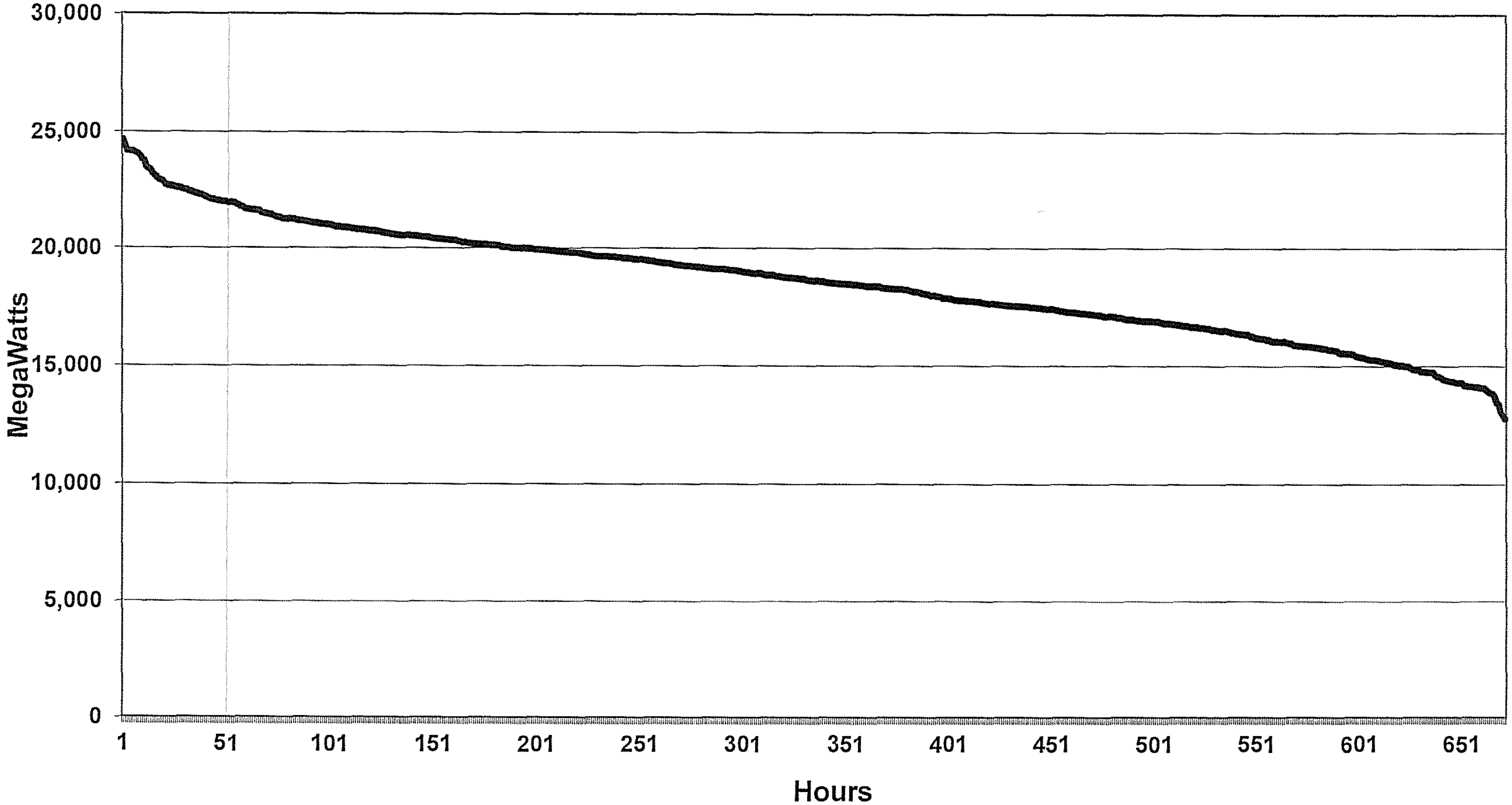
AEP System-East Zone
December 2013 Load Duration Curve
(Internal Load)



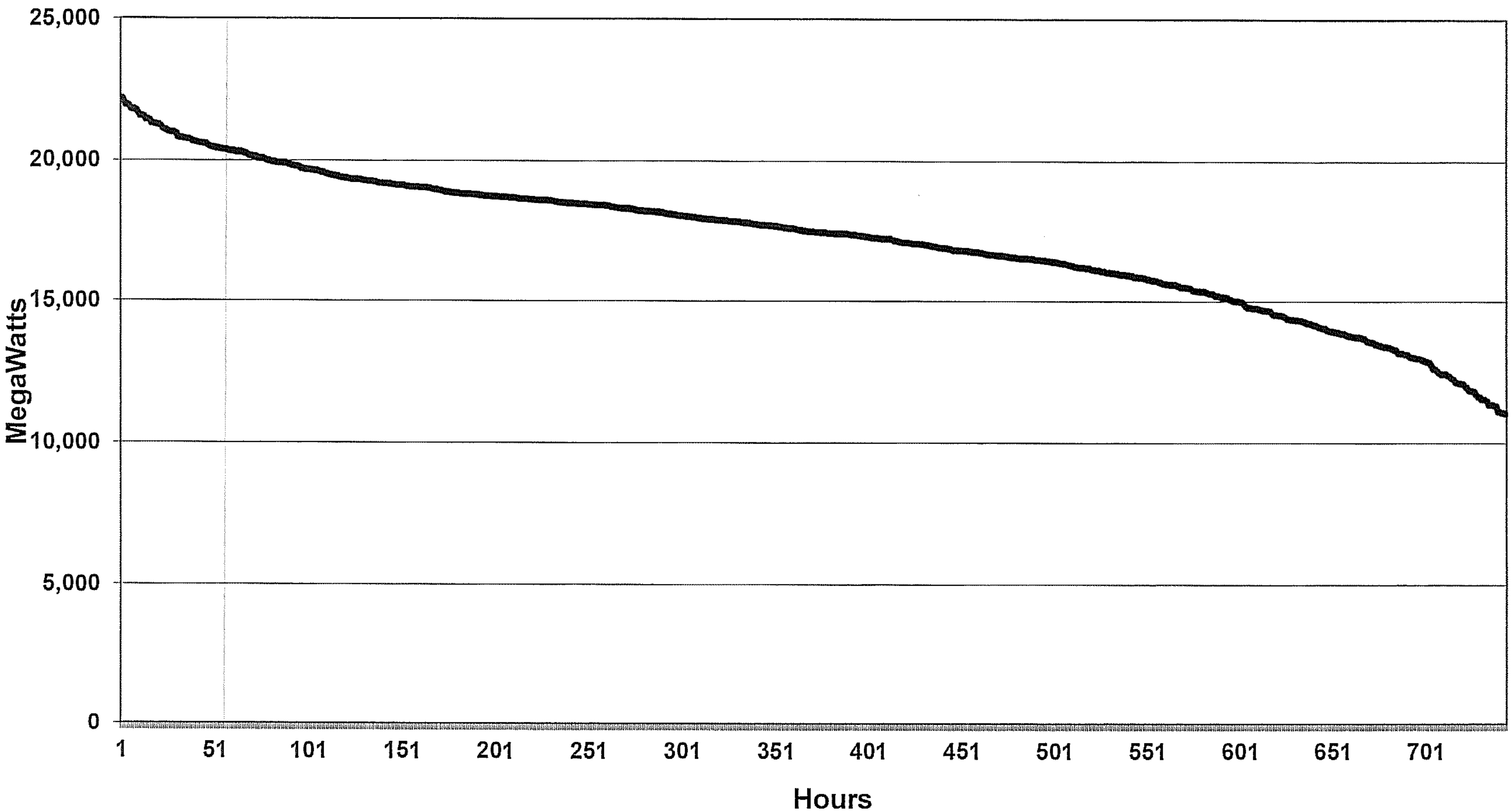
AEP System-East Zone
January 2013 Load Duration Curve
(System Load)



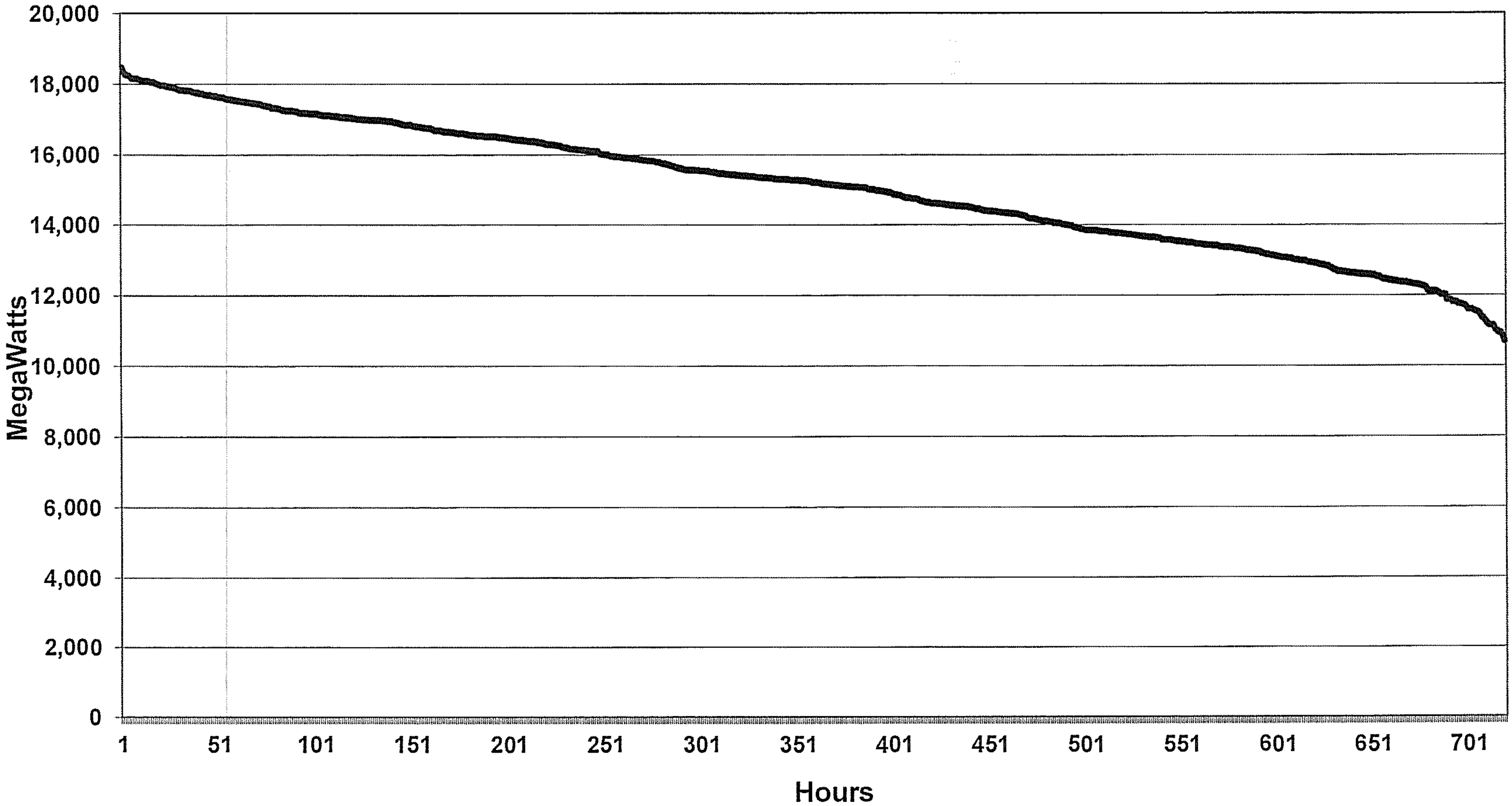
AEP System-East Zone
February 2013 Load Duration Curve
(System Load)



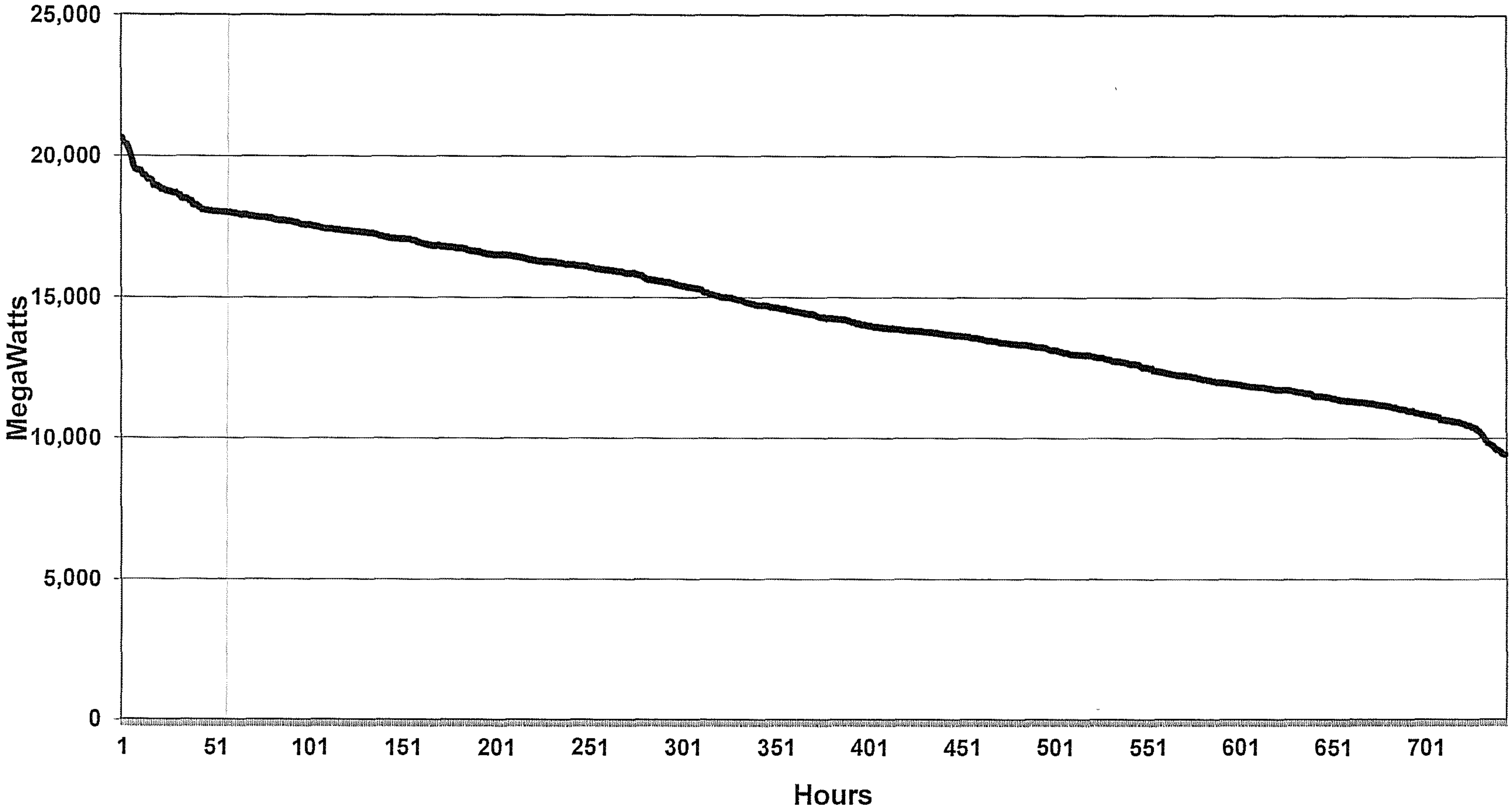
AEP System-East Zone
March 2013 Load Duration Curve
(System Load)



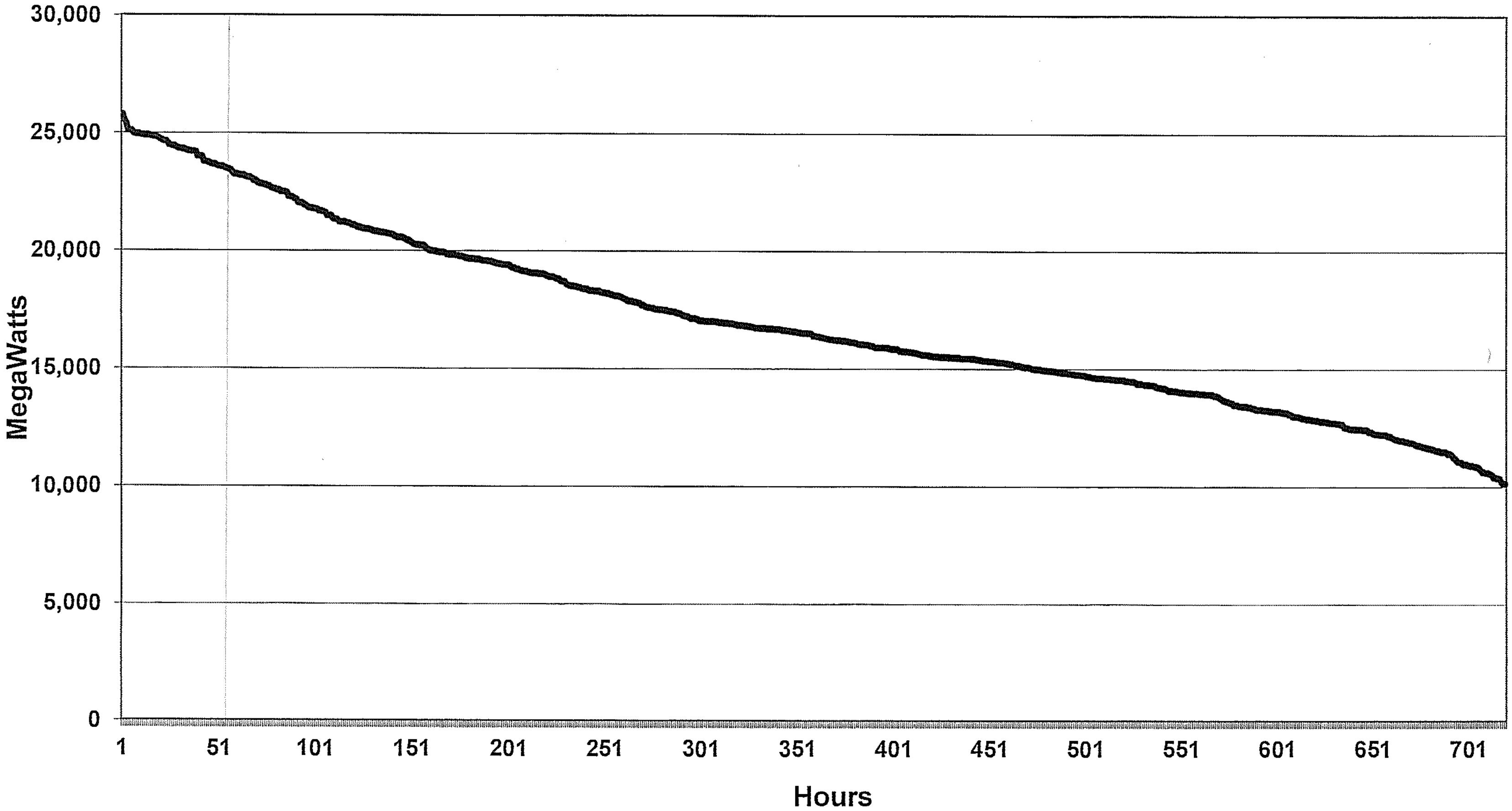
AEP System-East Zone
April 2013 Load Duration Curve
(System Load)



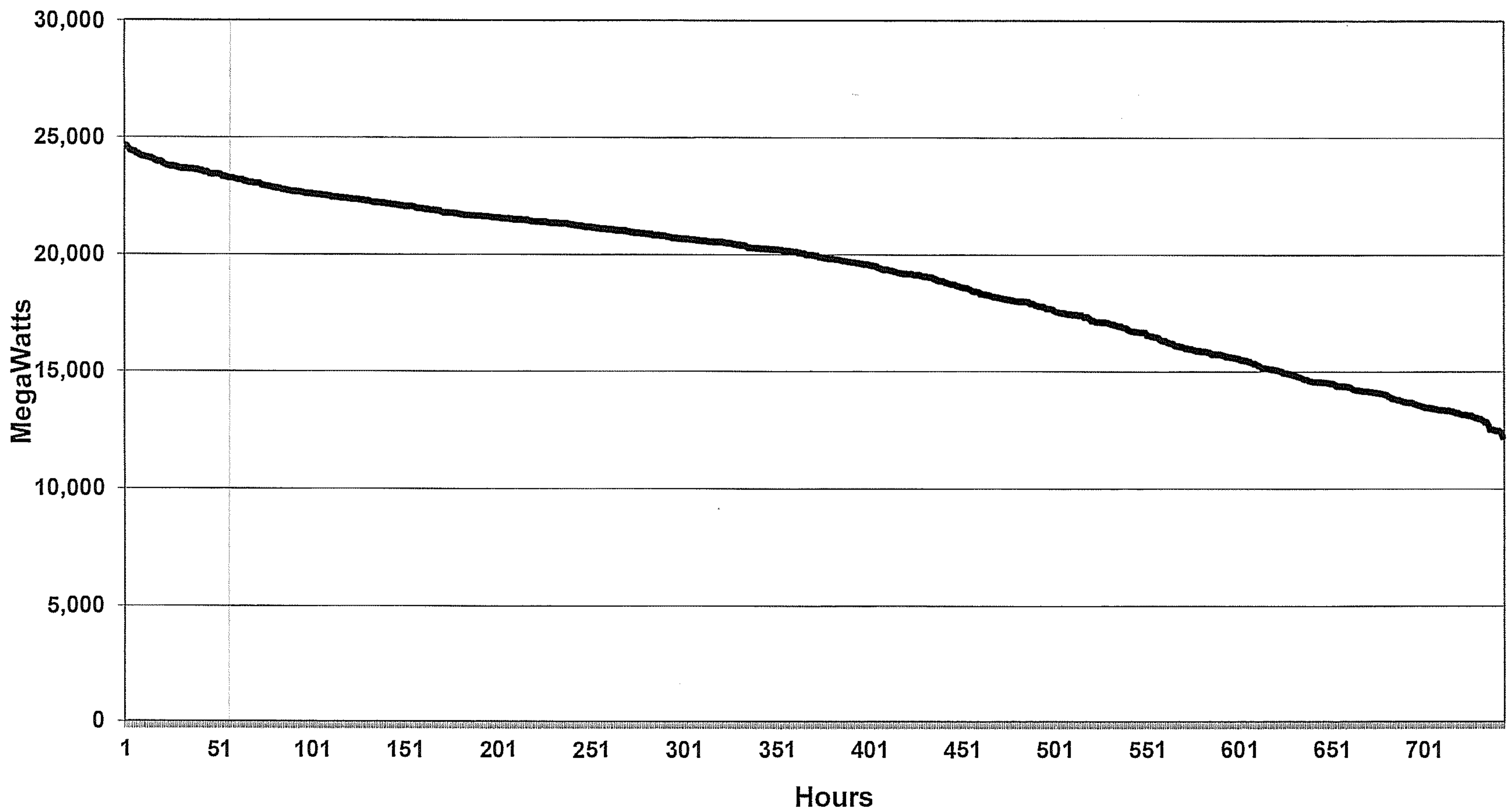
AEP System-East Zone
May 2013 Load Duration Curve
(System Load)



AEP System-East Zone
June 2013 Load Duration Curve
(System Load)

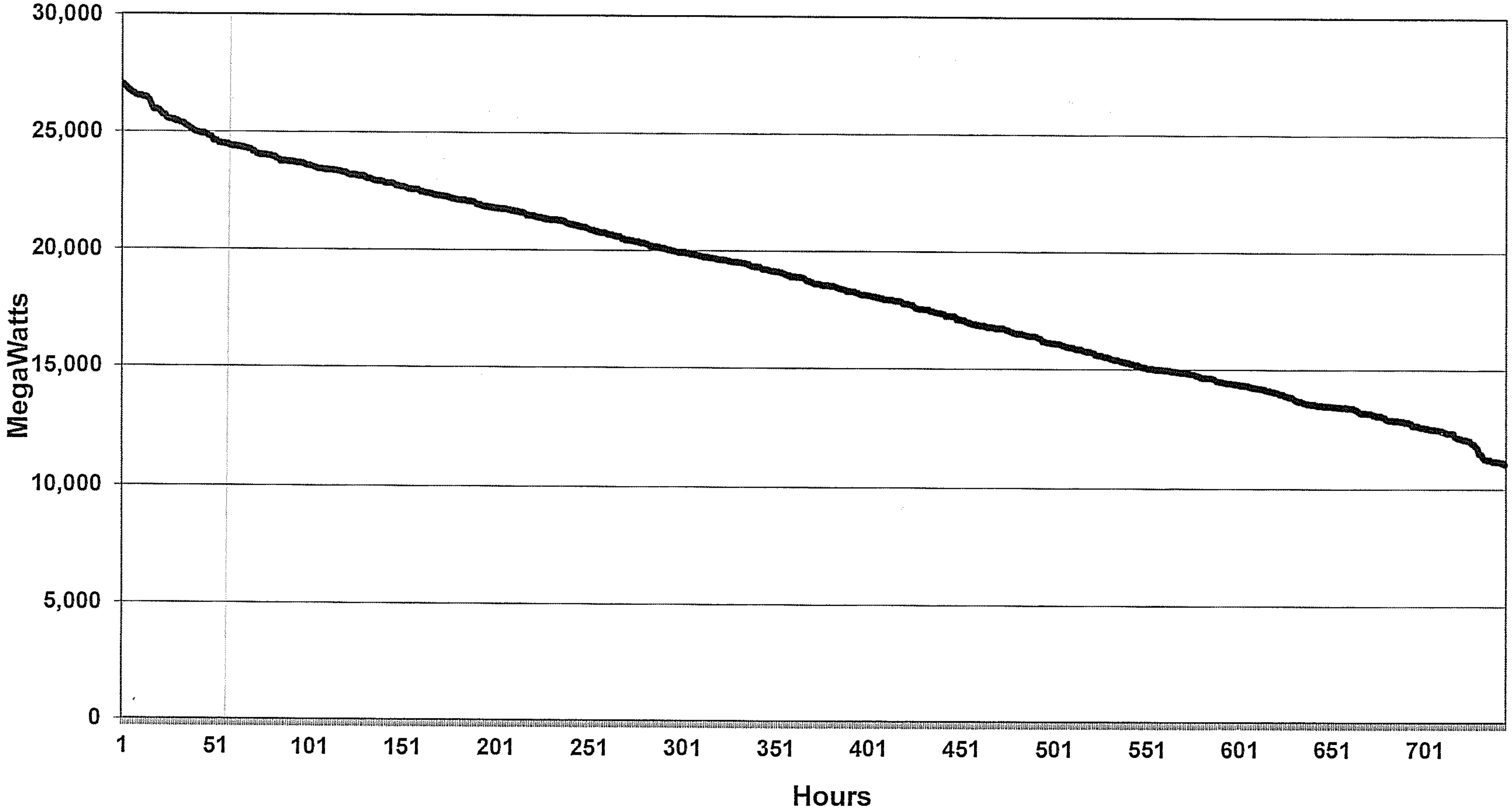


AEP System-East Zone
July 2013 Load Duration Curve
(System Load)

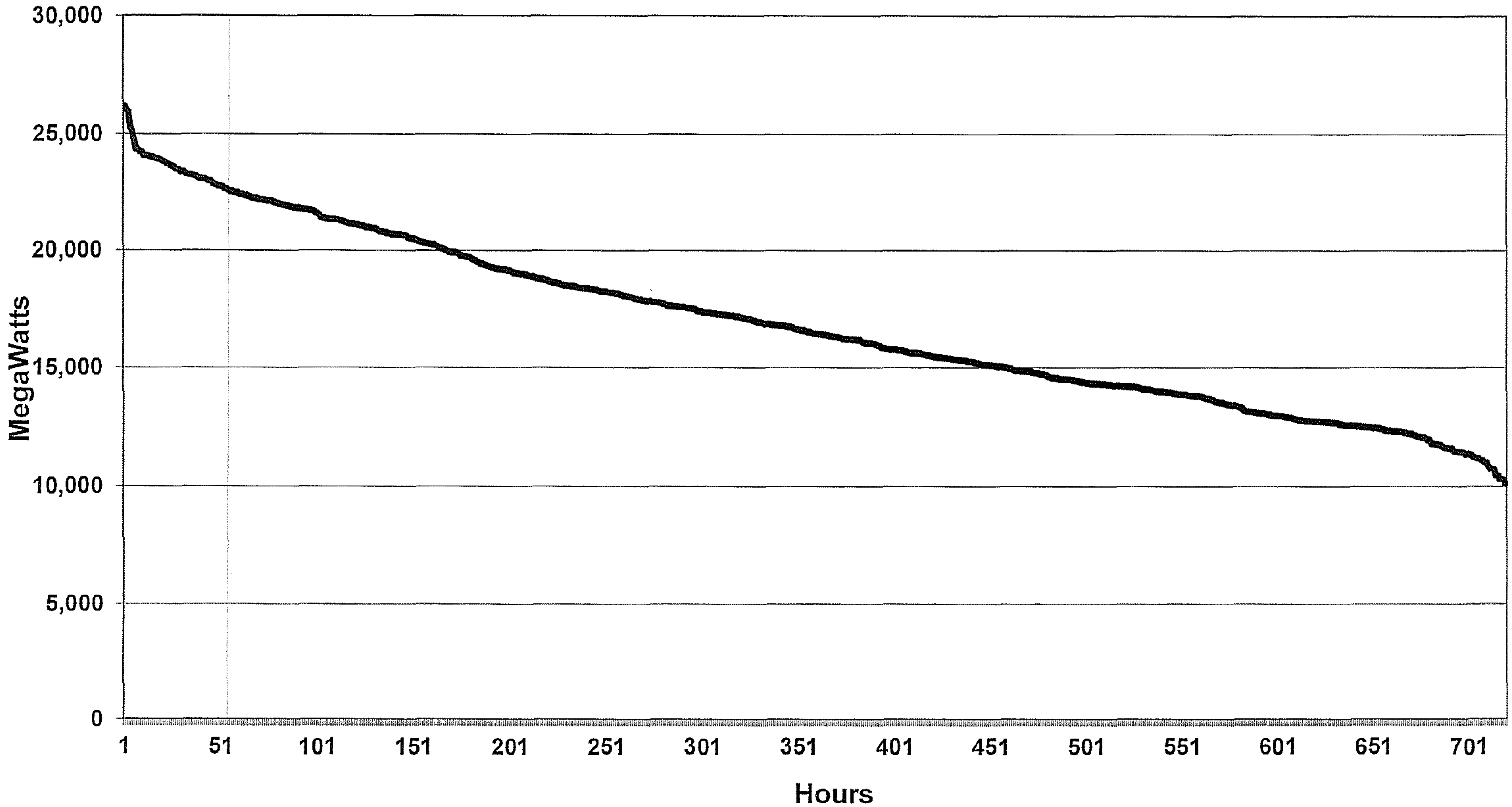


KPSC Administrative No. 387
Order Dated December 20, 2001
Calendar Year 2013
Annual Resource Assessment
Item No. 2
Attachment 1
Page 43 of 48

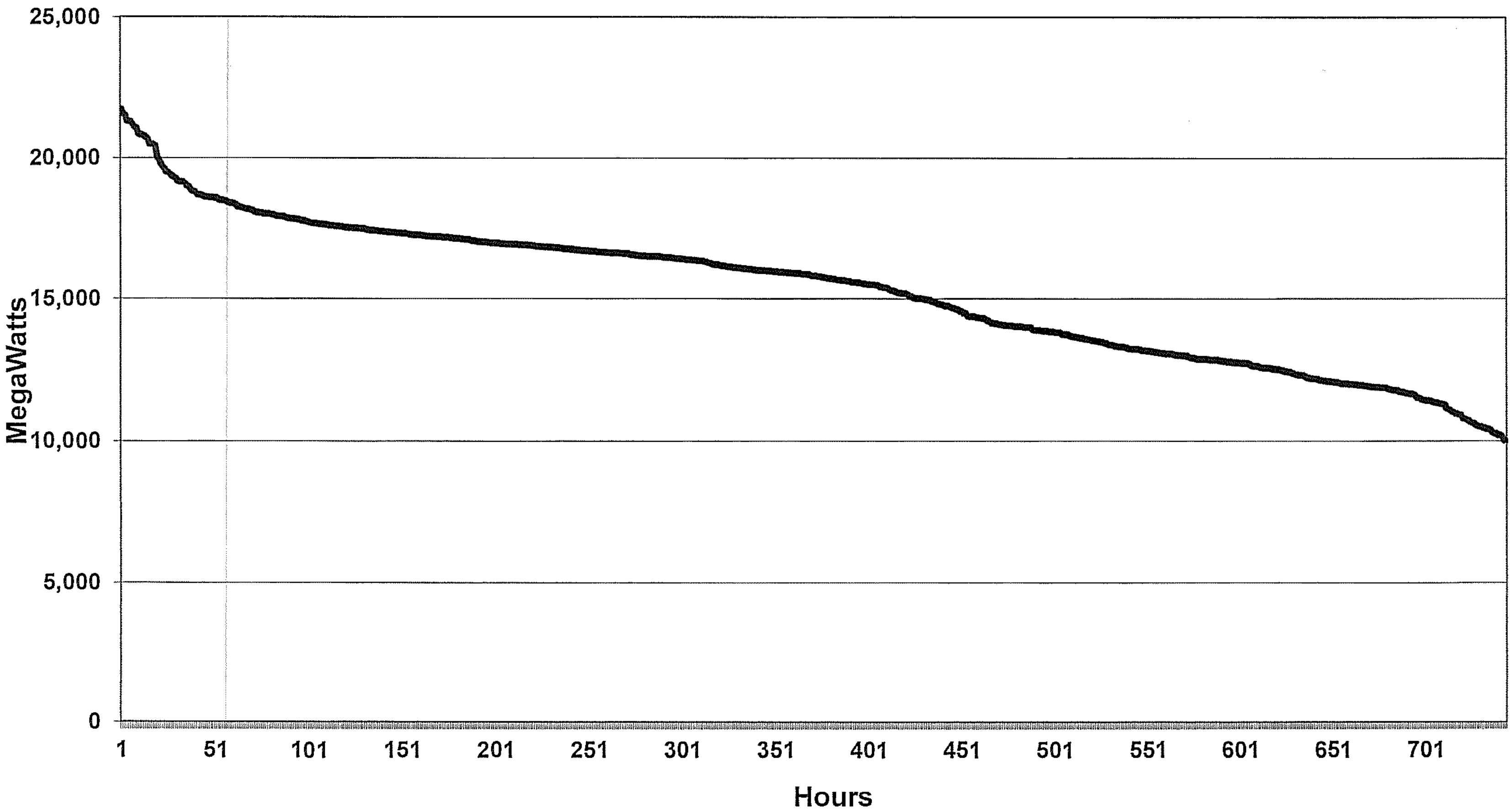
AEP System-East Zone
August 2013 Load Duration Curve
(System Load)



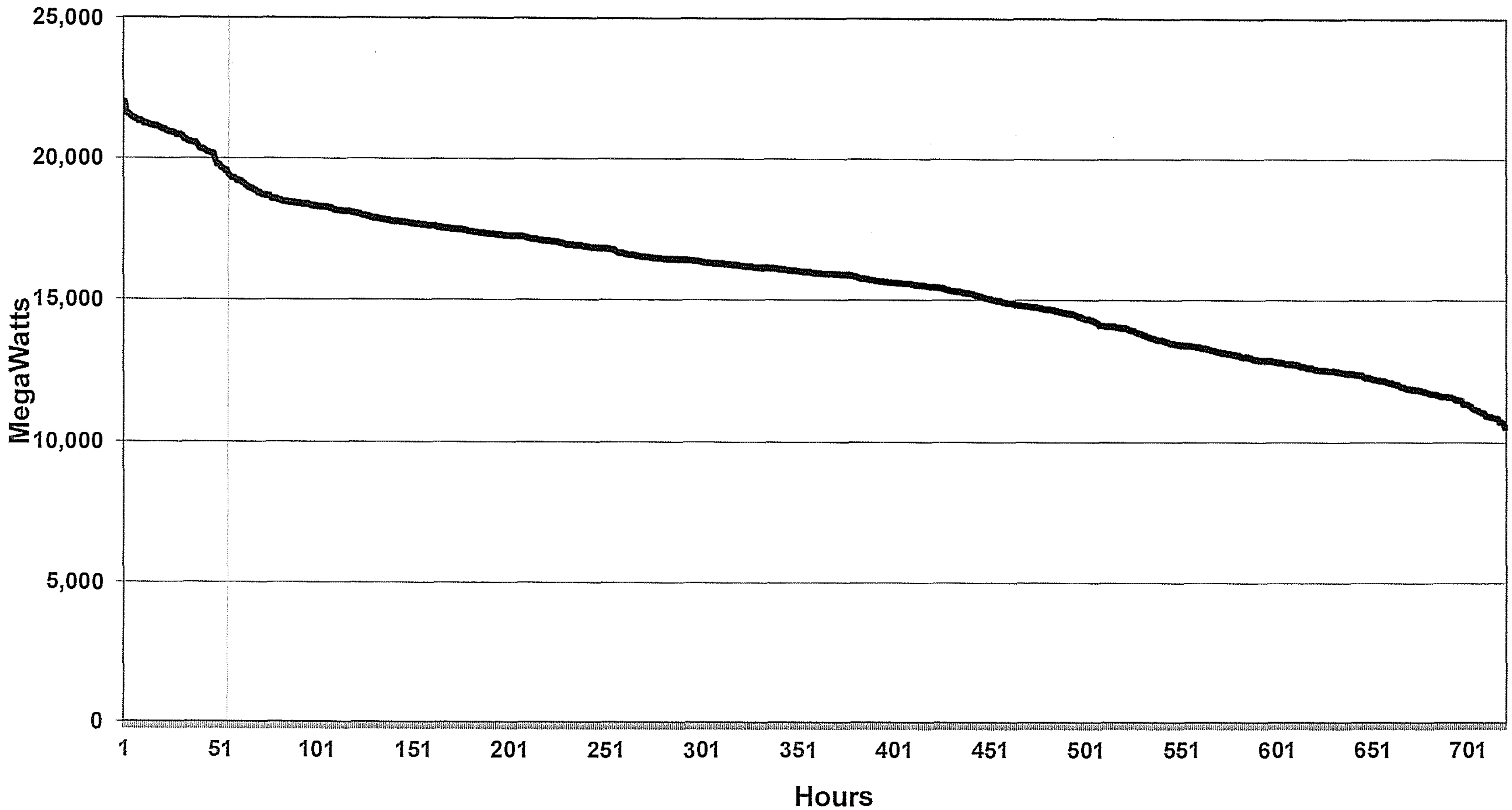
AEP System-East Zone
September 2013 Load Duration Curve
(System Load)



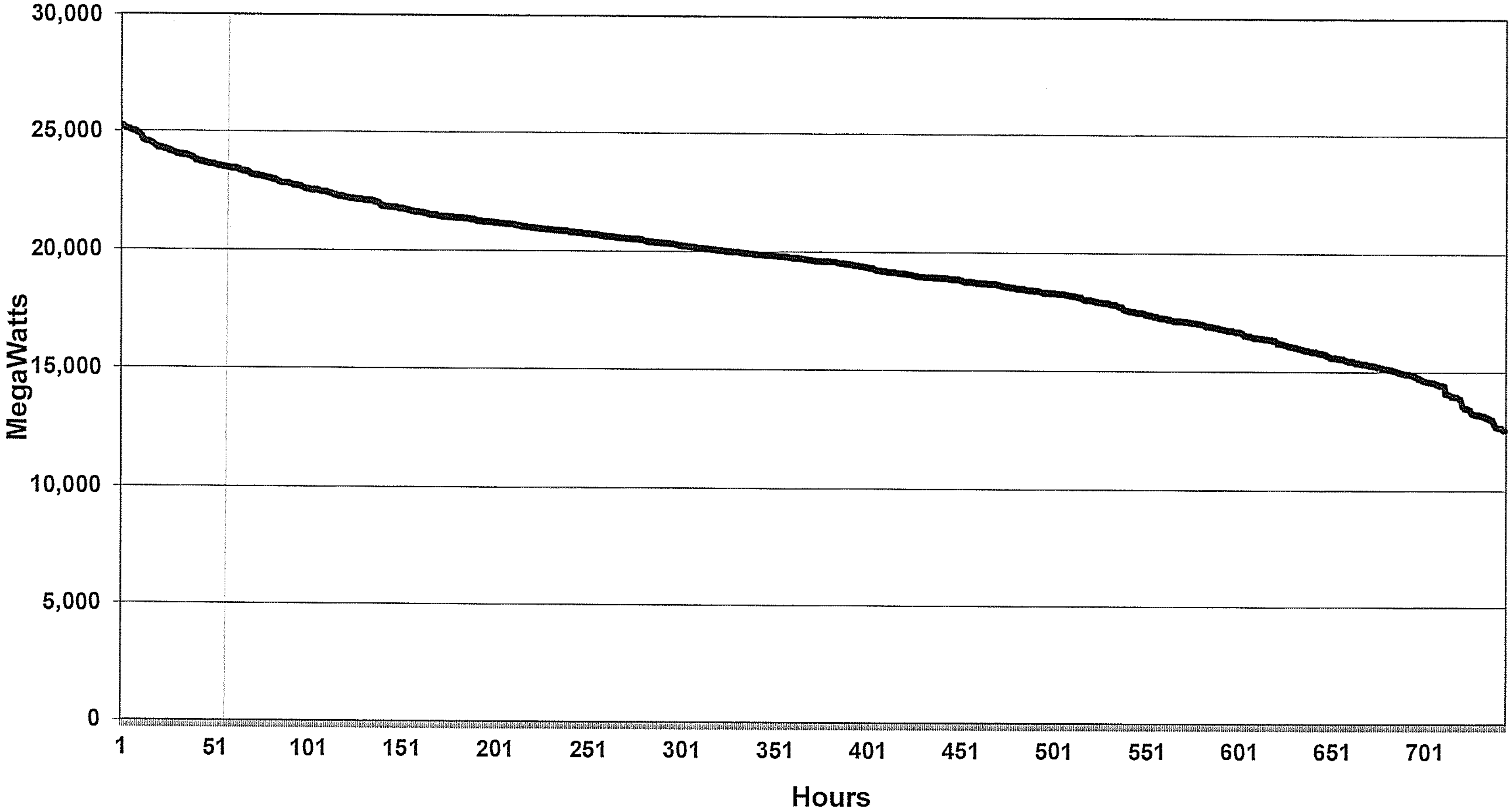
AEP System-East Zone
October 2013 Load Duration Curve
(System Load)



AEP System-East Zone
November 2013 Load Duration Curve
(System Load)



AEP System-East Zone
December 2013 Load Duration Curve
(System Load)



Kentucky Power Company

REQUEST

Based on the most recent demand forecast, the base case demand and energy forecasts and high case demand and energy forecasts for the current year and the following four years. The information should be disaggregated into (a) native load (firm and non-firm demand) and (b) off-system load (both firm and non-firm demand). Please provide the information for both Kentucky Power Company individually and the AEP-East Power Pool (pursuant to the Commission's December 13, 2004 Order in the Rockport UPSA extension, Case No. 2004-00420).

RESPONSE

Page 1 of Attachment 1 to this response provides Kentucky Power Company's forecast of seasonal peak internal demands and annual internal energy requirements. In addition, the associated high forecast for seasonal peak internal demands and internal energy requirements are provided on this page.

The AEP-East Power Pool terminated effective January 1, 2014, therefore loads for the AEP System-East are no longer available.

The off-system energy sales forecasts for Kentucky Power Company are provided on Page 2 of Attachment 1 to this response. Forecasts of off-system peak demand for Kentucky Power Company have not been developed and therefore, such forecasts are not available. In addition, high forecasts for off-system energy sales and peak demand have not been developed and therefore, such forecasts are not available. The AEP-East Pool terminated effective January 1, 2014, therefore loads for the AEP System-East Power Pool are no longer available.

WITNESS: Ranie K Wohnhas

Kentucky Power Company
Base and High Forecast
Energy Sales (GWH) and Seasonal Peak Demand (MW)
2014 - 2018

Year	Energy Sales Base	Energy Sales High	Summer Peak Demand Base	Summer Peak Demand High	Preceding Winter Peak Demand Base	Preceding Winter Peak Demand High
2014	6,958	6,984	1,132	1,136	1,432	1,437
2015	6,953	6,984	1,133	1,138	1,431	1,437
2016	6,970	7,034	1,134	1,144	1,432	1,445
2017	6,975	7,095	1,137	1,156	1,431	1,456
2018	6,979	7,151	1,139	1,167	1,431	1,466

Kentucky Power Company
Forecast Off-System Energy Sales (GWh)
2014 - 2018

Year	KPCo Off-System Sales
2014	2,284
2015	1,455
2016	1,002
2017	1,117
2018	1,041

Kentucky Power Company

REQUEST

The target reserve margin currently used for planning purposes, stated as a percentage of demand. If changed from what was in use in 2001, include a detailed explanation for the change. Please provide the information for both Kentucky Power Company individually and the AEP-East Power Pool (pursuant to the Commission's December 13, 2004 Order in the Rockport UPSA extension, Case No. 2004-00420).

RESPONSE

Due to the October 1, 2004 integration of AEP's Eastern System into the PJM Interconnection, AEP is now required to comply with the PJM mandated reserve margin.

The installed reserve margin requirement (IRM) is recalculated each year, depending on five-year average generation reliability, PJM load shape, and assistance available from neighboring regions. In addition, KPCo's responsibility to PJM depends on its twelve-month history of generator reliability and its peak demand diversity in relation to the PJM total load. Attachment 1 to this response provides an example of the PJM reserve requirement calculation.

For the 2014/15 delivery period PJM has set the IRM at 15.9%. For the 2015/16 delivery period PJM has set the IRM at 15.3% and 15.6% for the 2016/17 delivery period. For planning purposes KPCo assumed a 15.6% IRM for all future years. The resulting KPCo reserve margin for 2014/15 is 37.4% as shown in Attachment 2 of the response to Item No. 5. (This compares with 12% that AEP used, based on our own determinations, from the late 1990s until 2004, and 15% prior to that.)

AEP East utilities that own generation have for decades operated as part of the AEP integrated public utility holding company system under the now-repealed Public Utility Holding Company Act of 1935. As part of that arrangement, those companies coordinated the planning and operations of their respective generating resources pursuant to the AEP Interconnection Agreement (Pool or Pool Agreement).

On December 17, 2010, in accordance with Section 13.2 of the Pool Agreement, each of the Pool members provided notice to the other members (and to American Electric Power Service Corporation (AEPSC), as agent) to terminate the Pool Agreement (which includes the Interim Allowance Agreement (IAA)), on January 1, 2014. As a result, effective January 1, 2014, Kentucky Power Company (KPCo) became responsible for its own generation resources and maintenance of an adequate level of power supply resources to individually meet its own load requirements for capacity and energy, including any required reserve margin.

The AEP-East Power Pool no longer exists, and forecasts regarding it are no longer available.

WITNESS: Ranie K Wohnhas

PJM Reserve Margin Example For 2014/15 Planning Year

Line				Comment
1	**Factors**			
2	PJM Installed Reserve Margin (IRM)	=	15.90%	
3	PJM EFORd	=	6.05%	Based on 5-year average PJM EFORd
4	Forecast Pool Requirement (FPR)	=	1.089	FPR = (1 + Line 2) * (1 - Line 3)
5				
6	**Obligations**			
7	Total Load Obligation	=	1,156	With implied PJM diversity factor
8	UCAP Obligation	=	1,259	Line 4 * Line 7
9	UCAP Market Obligations	=	0	
10	Total UCAP Obligation	=	1,259	Line 8 + Line 9
11				
12	**Resources**			
13	Net ICAP	=	2,250	
14	KPCo EFORd	=	20.77%	MW-weighted average of Unit EFORds
15	Available UCAP	=	1,783	Line 13 * (1- Line 14)
16				
17	**Position**			
18	Net UCAP Position	=	524	Line 15 - Line 10
19	Net ICAP Position	=	661	Line 18 / (1- Line 14)
20				
21	Reserve Margin Percent	=	94.6	Question 5 attached Exhibit 5-2, Column (16)
22	Reserve Percent Required By PJM	=	37.4	Line 21 - (Line 19 / Question 5 attached Exhibit 5-2, Column (6)) * 100

Kentucky Power Company

REQUEST

Projected reserve margins stated in megawatts and as a percentage of demand for the current year and the following 4 years. Identify projected deficits and current plans for addressing these. For each year identify the level of firm capacity purchases projected to meet native load demand. Please provide the information for both Kentucky Power Company individually and the AEP-East Power Pool (pursuant to the Commission's December 13, 2004 Order in the Rockport UPSA extension, Case No. 2004-00420)

RESPONSE

Attachment 1 to this response provides projected winter peak demands, capabilities, and margins for KPCo for the winter seasons 2013/14 through 2017/18.

Attachment 2 to this response provides projected summer peak demands, capabilities, and margins for KPCO for 2014 through 2018 since the AEP System – East Zone view is no longer applicable after January 1, 2014 as outlined in the response to Item No. 4.

The AEP-East Power Pool no longer exists, and forecasts regarding it are no longer available.

WITNESS: Ranie K Wohnhas

KENTUCKY POWER COMPANY
Projected Winter Peak Demands, Generating Capabilities, and Margins

Winter Season	Peak Demand - MW: Internal Demand (a)	DSM (b)	Committed Sales	Total Demand	Inter-ruptible Demand	Total Demand	Capacity - MW: Existing Capacity & Chngs (c)	Sales: Net Sales (d)	Capacity Additions: Name/ Identifier	Capacity Additions: MW	Purchases: Annual Mkt. Purch.	Total Equivalent Capacity	Margin (f): MW	% of Demand
	(1)	(2)	(3)	(4)=(1)-(2+(3)	(5)	(6)=(4)-(5)	(7)	(8)		(9)	(10)	(11)=(7)-(8)+Sum(9)+(10)	(12)=(11)-(6)	(13)=[(12)/(6)]*100
2013/14	1,440	(8)	0	1,432	0	1,432	1,471	41		0	0	1,430	(2)	(0.1)
2014/15	1,442	(11)	0	1,431	0	1,431	2,251 (e)	0		0	0	2,251	820	57.3
2015/16	1,445	(13)	0	1,432	0	1,432	1,451	0		0	0	1,451	19	1.3
2016/17	1,446	(15)	0	1,431	0	1,431	1,433	0		0	0	1,433	2	0.1
2017/18	1,448	(17)	0	1,431	0	1,431	1,438	0	ecoPower (Biomass)	58.5	0	1,497	66	4.6

Notes: (a) Based on July 2013 Load Forecast.

(b) Existing plus approved and projected "Passive" EE, and VVO.

(c) Reflects KPCo's ownership ratio of the following winter capability assumptions.
EFFICIENCY IMPROVEMENTS:
2017/18: Rockport 1: 5 MW (turbine)
GAS CONVERSION RERATES:
2016/17: Big Sandy 1: (18 MW)
ASSUMED RETIREMENTS FOR PLANNING PURPOSES:
2015/16: Big Sandy 2: 800 MW

(d) Includes KPCo's share of:
RPM Auction Sales of 700 MW (UCAP) in 2013/14
Sale of 13 MW to Duke in 2013/14
3.6 MW capacity credit from SEPA's Philpot Dam via Blue Ridge contract in 2013/14

(e) Reflects the ownership transfer of 50% of Mitchell Units 1 & 2 effective 2014/15 (780 MW)

(f) Represents margin relative to KPCo peak demand, not PJM requirement.

KENTUCKY POWER COMPANY
Projected Summer Peak Demands, Generating Capabilities, and Margins

	Peak Demand - MW						Capacity - MW						Reserve Margin Before Interruptible w/ New Capacity		Reserve Margin After Interruptible w/ New Capacity		PJM ICAP Position After Interruptible w/ New Capacity	
Summer Season	Internal Demand (a)	Interruptible Demand Response (b)	DSM (c)	Net KPCo Internal Demand	Net Other Committed Sales	Total KPCo Demand	Existing Capacity & Planned Changes (d)	Committed Net Sales	Planned Capacity Additions Name/ Identifier	Planned Capacity Additions MW	Annual Purch.	Total Capacity	MW	% of Demand	MW	% of Demand	Reserve % Required By PJM	Net Position MW
	(1)	(2)	(3)	(4)=sum(1 thru 3)	(5)	(6)=(4)+(5)	(7)	(8)	(9)	(10)	(11)	(12)=(7)-(8)+Sum(10)+(11)	(13)=(12)-((6)-(2))	(14)=(13)/((6)-(2))*100	(15)=(12)-(6)	(16)=(15)/(6)*100		
2014	1,157	0	(1)	1,156	0	1,156	2,250					2,250	1,094	94.6	1,094	94.6	37.4	661
2015	1,180	0	(2)	1,178	0	1,178	1,450					1,450	272	23.1	272	23.1	16.5	60
2016	1,198	0	(3)	1,195	0	1,195	1,432					1,432	237	19.8	237	19.8	17.7	25
2017	1,066	0	(3)	1,063	0	1,063	1,432		ecoPower (Biomass)	58.5		1,491	428	40.3	428	40.3	17.8	239
2018	1,069	0	(5)	1,064	0	1,064	1,438					1,497	433	40.7	433	40.7	17.9	243

Notes: (a) Based on (July 2013) Load Forecast (with implied PJM diversity factor)

(b) Demand Response approved by PJM in the prior planning year plus forecasted "Active" DR

(c) For PJM planning purposes, the ultimate impact of new DSM is 'delayed' about 4 years to represent the ultimate recognition of these amounts through the PJM-originated load forecast process.

(d) Reflects KPCo's ownership ratio of the following summer capability assumptions:
EFFICIENCY IMPROVEMENTS:
2018: Rockport 1: 6 MW (turbine)
GAS CONVERSION RERATES:
2016: Big Sandy 1 (18 MW)
ASSUMED RETIREMENTS FOR PLANNING PURPOSES:
2015: Big Sandy 2: 800 MW

Kentucky Power Company

REQUEST

A list that identifies scheduled outages or retirements of generating capacity during the current year and the following four years.

RESPONSE

Please see Attachment 1 to this response.

WITNESS: Ranie K Wohnhas

Big Sandy Plant

Year	Unit 1	Unit 2
2014	4 weeks	4 weeks
2015	More than 4 weeks	No Outage Scheduled/Planned Retirement
2016	More than 4 weeks	Retired
2017	*No Outage Scheduled	Retired
2018	*No Outage Scheduled	Retired

*The Company currently is seeking a Certificate of Convenience and Public Necessity to convert Big Sandy Unit 1 to natural gas.

Mitchell Plant

Year	Unit 1	Unit 2
2014	Less than 4 weeks	Less than 4 weeks
2014	4 Weeks	
2015	4 weeks	More than 4 weeks
2015	More than 4 weeks	
2016		Less than 4 weeks
2017	Less than 4 weeks	Less than 4 weeks
2018	Less than 4 weeks	More than 4 weeks

Kentucky Power Company

REQUEST

Identify all planned base load or peaking capacity additions to meet native load requirements over the next 10 years. Show the expected in-service date, size and site for all planned additions. Include additions planned by the utility, as well as those by affiliates, if constructed in Kentucky or intended to meet load in Kentucky. Please provide the information for both Kentucky Power Company individually and the AEP-East Power Pool (pursuant to the Commission's December 13, 2004 Order in the Rockport UPSA extension, Case No. 2004-00420).

RESPONSE

Kentucky Power Company entered into a contract agreement to purchase the output of the 58.5 MW ecoPower Hazard LLC biomass plant, located near Hazard, Kentucky. Generation from the ecoPower facility is expected to begin in 2017.

As a result of the January 1, 2014 termination of the AEP Interconnection Agreement ("pool agreement"), a mix of generation resources is needed to meet KPCo's projected capacity needs, on a stand-alone basis, through 2024. Currently no additional resources aside from the aforementioned ecoPower purchase are planned for KPCo.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

The following transmission energy data for the just completed calendar year and the forecast for the current year and the following four years:

a. Total energy received from all interconnections and generation sources connected to the transmission system.

b. Total energy delivered to all interconnections on the transmission system

RESPONSE

Please see Attachment 1 to this response.

WITNESS: Ranie K Wohnhas

8(a) All quantities represent metered values.

Received from (MWh):	2008 (Actual)	2009 (Actual)	2010 (Actual)	2011 (Actual)	2012 (Actual)	2013 (Actual)	2014	2015	2016	2017	2018
Appalachian Power (1)	7,826,055	4,637,687	5,042,019	4,230,880	4,338,641	4,631,523	(4)	(4)	(4)	(4)	(4)
Ohio Power (1)	8,832,135	10,872,502	11,316,622	11,393,398	10,644,478	10,066,676	(4)	(4)	(4)	(4)	(4)
East Ky Power Coop	402,847	481,140	412,663	510,543	394,193	386,124	(4)	(4)	(4)	(4)	(4)
LGE(Kentucky Utilities)	810,871	933,540	884,267	780,095	730,063	565,818	(4)	(4)	(4)	(4)	(4)
TVA	448,365	523,823	604,964	654,875	551,305	566,823	(4)	(4)	(4)	(4)	(4)
Illinois Power Co. (2)	33,190	35,408	46,376	59,956	136,798	111,628	(5)	(5)	(5)	(5)	(5)
Illinois Power Co. (3)	23,629	16,769	20,742	26,552	101,471	89,276	(5)	(5)	(5)	(5)	(5)
Big Sandy Generating Plant	6,021,182	6,262,165	6,552,258	6,372,925	2,661,344	2,764,447	2,177,950	972,794	76,586	100,957	109,140
*Mitchell 1 & 2 (KPCo Share 50%)							3,121,055	3,713,573	4,544,876	4,578,073	4,548,186
*Rockport Purchase Power Agreement							2,082,336	2,006,845	2,482,695	2,487,699	2,455,178
							7,381,341	6,693,211	7,104,157	7,166,729	7,112,505

8(b) All quantities represent metered values.

Delivered to (MWh) :	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Appalachian Power (1)	15,917,326	15,589,080	16,340,364	15,816,607	11,673,720	11,550,084	(4)	(4)	(4)	(4)	(4)
Ohio Power (1)	360,333	465,000	466,832	494,931	526,005	371,910	(4)	(4)	(4)	(4)	(4)
East Ky Power Coop	213,189	154,558	154,000	176,721	206,810	136,118	(4)	(4)	(4)	(4)	(4)
LGE(Kentucky Utilities)	14	11	23	1	36	0	(4)	(4)	(4)	(4)	(4)
TVA	62	0	0	1	0	0	(4)	(4)	(4)	(4)	(4)
Vanceburg and Olive Hill	101,657	95,284	103,058	95,607	95,525	95,502	(6)	(6)	(6)	(6)	(6)

Notes: (1) An AEP System company.
(2) At the Riverside independent power producing plant (IPP) in Lawrence County, KY.
(3) At the Foothills independent power producing plant (IPP) in Lawrence County, KY.
(4) The Company does not forecast metered interchange; however, the future years' energy flows are not expected to be materially different from the year 2013 actuals.
(5) The Company does not, and can not, forecast energy production output from an IPP.
(6) This is a 3rd Party Firm Load that is served by Kentucky Power.

*Kentucky Power resources that are not connected to the Kentucky Power Transmission System

Kentucky Power Company

REQUEST

The following transmission energy data for the just completed calendar year and the forecast for the current year and the following four years.

c. Peak load capacity of the transmission system.

d. Peak demand for summer and winter seasons on the transmission system.

RESPONSE

c. The maximum amount of electric energy that can be transmitted through a transmission network is a function of the level of the load and generation connected to the transmission system as well as the level and direction of transmission service into, out of, and through the network. Therefore, the 'Peak Load Capacity' of the transmission system cannot be quantified as a single value.

The Kentucky Power transmission system capacity is designed to serve the existing and projected load. It is also designed to reliably serve the load for any single contingency outage of a line, transformer or generator. The existing transmission system together with the capacity additions listed in response to Item No. 9 will provide adequate capacity to serve the existing and projected loads shown in the table below.

Kentucky Power Company

d. The actual summer and winter peak demands are shown below for 2013/2014. In addition, forecasted summer and winter peak demands for 2014 through 2018 are also shown in the table below.

Kentucky Power Company Seasonal Peak Demand Actual 2013 and Forecast 2014-2018		
Year	Summer Peak Demand (MW)	Preceding Winter Peak Demand (MW)
2013	1,138*	1,409*
2014	1,132	1,645*
2015	1,133	1,432
2016	1,134	1,431
2017	1,137	1,431
2018	1,139	1,432

*Based on Actual Load Data

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Identify all planned transmission capacity additions for the next 10 years. Include the expected in-service date, size and site for all planned additions and identify the transmission need each addition is intended to address.

RESPONSE

Please see Attachment 1 to this response. Confidential treatment is being sought for portions of the attachment.

WITNESS: Ranie K Wohnhas

The following projects are planned for the Kentucky Power Company transmission system:

Hazard Area Improvements Project – This project, which includes the Bonnyman-Softshell line, will provide another 138 kV source into the Hazard area of eastern Kentucky. Station and line work will be required. This project will provide single contingency reliability to the Hazard area subtransmission system and double contingency reliability to the area 138 kV system. Current projected in-service date is December 2014.

Big Sandy Area Improvements – This project will install a second 765/345 kV transformer at the Baker 765 kV station. This project will provide double contingency reliability to the critical transmission system. The anticipated in-service date would be June 2015.

Thelma and Busseyville Station Upgrades – This project will address thermal overload concerns on the Big Sandy-Thelma 138kV circuit. Station and line work will be required. This project will increase the thermal rating on the Big Sandy-Thelma 138kV line. Current projected in-service date is June 2015.

Dorton 138kV Circuit Breaker Project- This project will install three 138kV circuit breakers and one circuit switcher at Dorton Station. The project will solve thermal loading concerns and operational reliability concerns. The current projected in-service date is June 2015.

Johns Creek and Stone Station Upgrades – This project will install two new 138 kV circuit breakers at Johns Creek and one 138kV circuit breaker at Stone Station. This project will provide additional reliability to customers, operational flexibility, and voltage support under contingency conditions. Current projected in-service date is June 2015.

Cedar Creek Station Upgrades – This project will install two new 138 kV circuit breakers at Cedar Creek Station. This project will provide operational benefits and provide voltage support for single contingency line outages. Current projected in-service date is April 2016.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Kentucky Power Company – Electricity Price in Forecast Modeling

Kentucky Power Company confirms that it takes electricity price and the effects of its changes into consideration in every load forecast, including the forecast filed on April 30, 2014, in Administrative Case No. 387. As was further requested in the Commission's letter dated May 31, 2013, the following provides a discussion of the impacts of prices on electricity sales and how price is accounted for in the load forecast.

An understanding of the relationship between energy prices and energy consumption is fundamental to developing a forecast of electricity consumption. In theory, the effect of a change in the price of a good on the consumption of that good can be disaggregated into two effects, the "income" effect and the "substitution" effect. The income effect refers to the change in consumption of a good attributable to the change in real income incident to the change in the price of that good. For most goods, a decline in real income would induce a decline in consumption. The substitution effect refers to the change in the consumption of a good associated with the change in the price of that good relative to the prices of all other goods. The substitution effect is assumed to be negative in all cases; that is, a rise in the price of a good relative to other, substitute goods would induce a decline in consumption of the original good. Thus, if the price of electricity were to rise, the consumption of electricity would fall, all other things being equal. Part of the decline would be attributable to the income effect; consumers must make decisions on how to allocate their budget to purchase electricity services and other goods and services after the price of electricity rises. Part would be attributable to the substitution effect; consumers would substitute relatively cheaper fuels for electricity once its price had risen.

The magnitude of the effect of price changes on consumption differs over different time horizons. In the short-term, the effect of a rise in the price of electricity is severely constrained by the ability of consumers to substitute other fuels or to incorporate more electricity-efficient technology. (The fact that the Company's short-term energy consumption models do not include price as an explanatory variable is a reflection of the belief that this constraint is severe). In the long-term, however, the constraints on substitution are lessened for a number of reasons. First, durable equipment stocks begin to reflect changes in relative energy prices by favoring the equipment using the fuel that was expected to be cheaper; second, heightened consumer interest in saving electricity, backed by willingness to pay for more efficiency, spurs development of conservation technology; third, existing technology, too expensive to implement commercially at previous levels of energy prices, becomes feasible at the new, higher energy prices; and fourth, normal turnover of electricity-using equipment contributes to a higher average level of energy efficiency.

For these reasons, energy price changes are expected to have an effect on long-term energy consumption levels. As a reflection of this belief, most of the Company's long-term forecasting models, including the residential, commercial, manufacturing and mine power energy sales models, incorporate the price of electricity as an explanatory variable. The residential Statistically Adjusted End-Use (SAE) Model uses price in development of explanatory variables. There are a variety of short- and long-run elasticities utilized in this analysis. In addition to electricity prices, the residential SAE model utilizes the price of natural gas and associated cross-price elasticities. Likewise, the commercial SAE model incorporates electricity price and an associated price elasticity to develop explanatory variables. Manufacturing and mine power have price as an explanatory variable. In these cases, the coefficient of the price variable provides a quantitative measure of the sensitivity of the forecast value to a change in price. The manufacturing model incorporates the price of natural gas to consumers in the state of Kentucky.