KENTUCKY POWER
A unit of American Electric Power

Kentucky Power
P O Box 5190
101A Enterprise Drive
Frankfort, KY 40602
KentuckyPower.com

RECEIVED
APR 28 2010
PUBLIC SERVICE COMMISSION

April 28, 2010

Jeff R. Derouen
Executive Director
Public Service Commission of Kentucky
PO Box 615
Frankfort, KY 40602-0615

RE: Administrative Case No. 387

Dear Mr. Derouen:

Pursuant to the Commission's October 7, 2005 Order in the above case please find enclosed and accept for filing original and ten copies of the 2009 Annual Resource Assessment for Kentucky Power Company. Also enclosed are one copy of the Kentucky Power Company 2009 FERC Form No. 1 and one copy of the 2009 Annual Public Service Commission Utility Financial Report for Kentucky Power Company.

If you have any questions, please do not hesitate to contact me at (502) 696-7010.

Sincerely yours,

Errol K Wagner
Director Regulatory Services

cc: Mark R. Overstreet

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF :

A REVIEW OF THE ADEQUACY OF KENTUCKY'S GENERATION CAPACITY AND TRANSMISSION SYSTEM	))))	ADMINISTRATIVE CASE NO. 387

****

RESPONSE OF KENTUCKY POWER COMPANY

TO

COMMISSION ORDER DATED DECEMBER 20, 2001

28

April 30, 2010

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 2 of this response provides actual and weather normalized 2009 monthly peak internal demands for Kentucky Power Company and AEP System-East. Kentucky Power Company and AEP System-East had 0 and 1,024 MW of contractual interruptible capacity, respectively.

Page 3 of this response provides actual 2009 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.

WITNESS: Errol K Wagner

Kentucky Power Company and AEP System-East Zone
Actual and Weather Normalized Peak Internal Demand (MW)
2009

	Kentucky Power Company				AEP System-East Zone			
Month	Peak	Peak Day	Peak Hour	Normalized Peak	Peak	Peak Day	Peak Hour	Normalized Peak
January	1,674	1/16/2009	9	1,562	22,270	1/16/2009	8	20,547
February	1,585	2/5/2009	8	1,430	21,603	2/5/2009	8	19,649
March	1,556	3/3/2009	8	1,333	20,349	3/3/2009	8	18,062
April	1,141	4/8/2009	7	1,086	16,464	4/7/2009	8	15,301
May	1,000	5/22/2009	15	1,027	15,872	5/27/2009	16	15,951
June	1,147	6/19/2009	16	1,169	19,043	6/25/2009	15	18,779
July	1,081	7/27/2009	16	1,251	18,291	7/28/2009	15	19,425
August	1,163	8/10/2009	16	1,223	19,826	8/10/2009	14	20,291
September	1,040	9/22/2009	14	1,087	16,724	9/15/2009	16	17,536
October	1,070	10/19/2009	8	1,058	15,899	10/19/2009	7	15,647
November	1,113	11/6/2009	8	1,242	16,187	11/30/2009	20	17,315
December	1,434	12/11/2009	8	1,375	19,309	12/11/2009	8	19,469

Kentucky Power Company and AEP System-East Zone
Actual Peak System Demand (MW)
2009

	Kentucky Power Company			AEP System-East Zone		
Month	Peak	Peak Day	Peak Hour	Peak	Peak Day	Peak Hour
January	1,797	1/16/2009	9	24,235	1/16/2009	8
February	1,731	2/5/2009	8	23,909	2/5/2009	8
March	1,693	3/3/2009	8	22,541	3/3/2009	8
April	1,270	4/8/2009	7	18,594	4/7/2009	8
May	1,103	5/22/2009	15	17,510	5/27/2009	16
June	1,272	6/19/2009	16	21,514	6/24/2009	16
July	1,207	7/27/2009	16	20,359	7/16/2009	16
August	1,300	8/10/2009	16	22,029	8/10/2009	14
September	1,172	9/22/2009	16	18,742	9/15/2009	16
October	1,192	10/19/2009	8	17,616	10/19/2009	7
November	1,225	11/6/2009	8	18,265	11/30/2009	20
December	1,586	12/11/2009	8	21,670	12/11/2009	8

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).

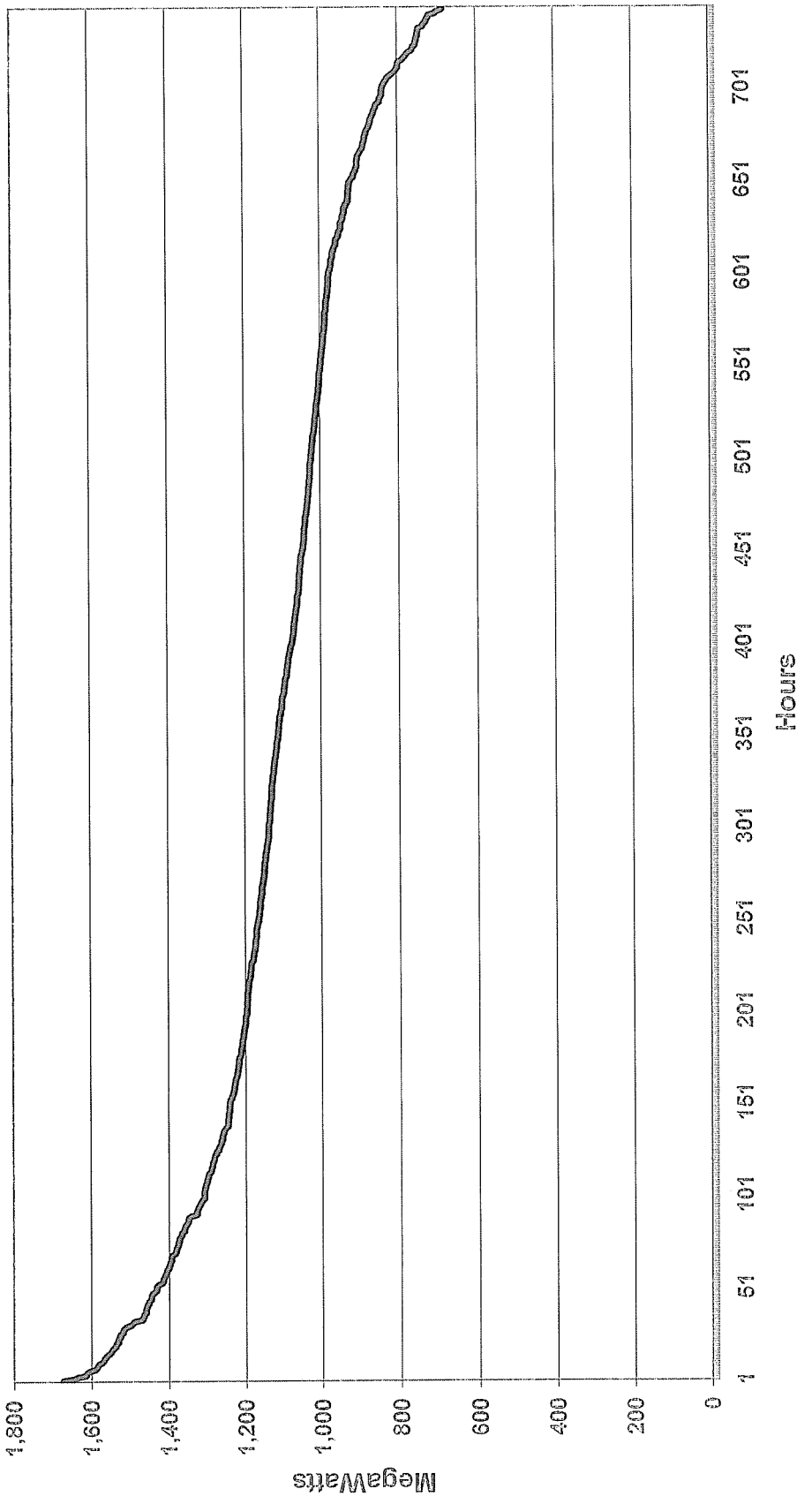
RESPONSE

Pages 2 through 13 provide 2009 monthly load duration curves for Kentucky Power Company's internal load. Pages 14 through 25 provide 2009 monthly load duration curves for Kentucky Power Company's system load. Pages 26 through 37 provide 2009 monthly load duration curves for AEP System-East's internal load. Pages 38 through 49 provide 2009 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.

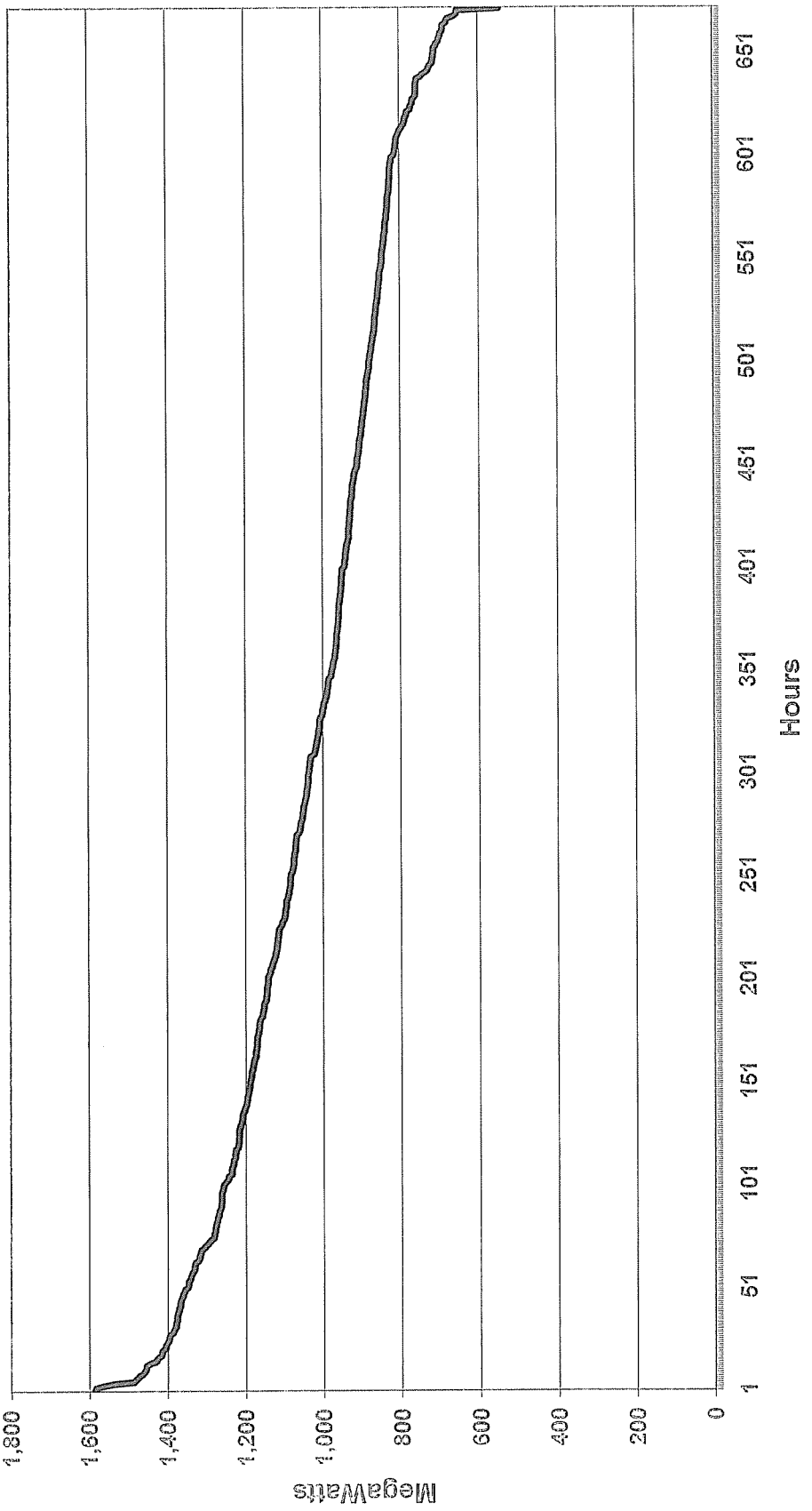
Weather-normalized monthly internal peaks for Kentucky Power Company and AEP System-East are provided on Page 2 of Item Number 1. Weather normalized system peaks have not been developed and therefore, are not available.

WITNESS: Errol K Wagner

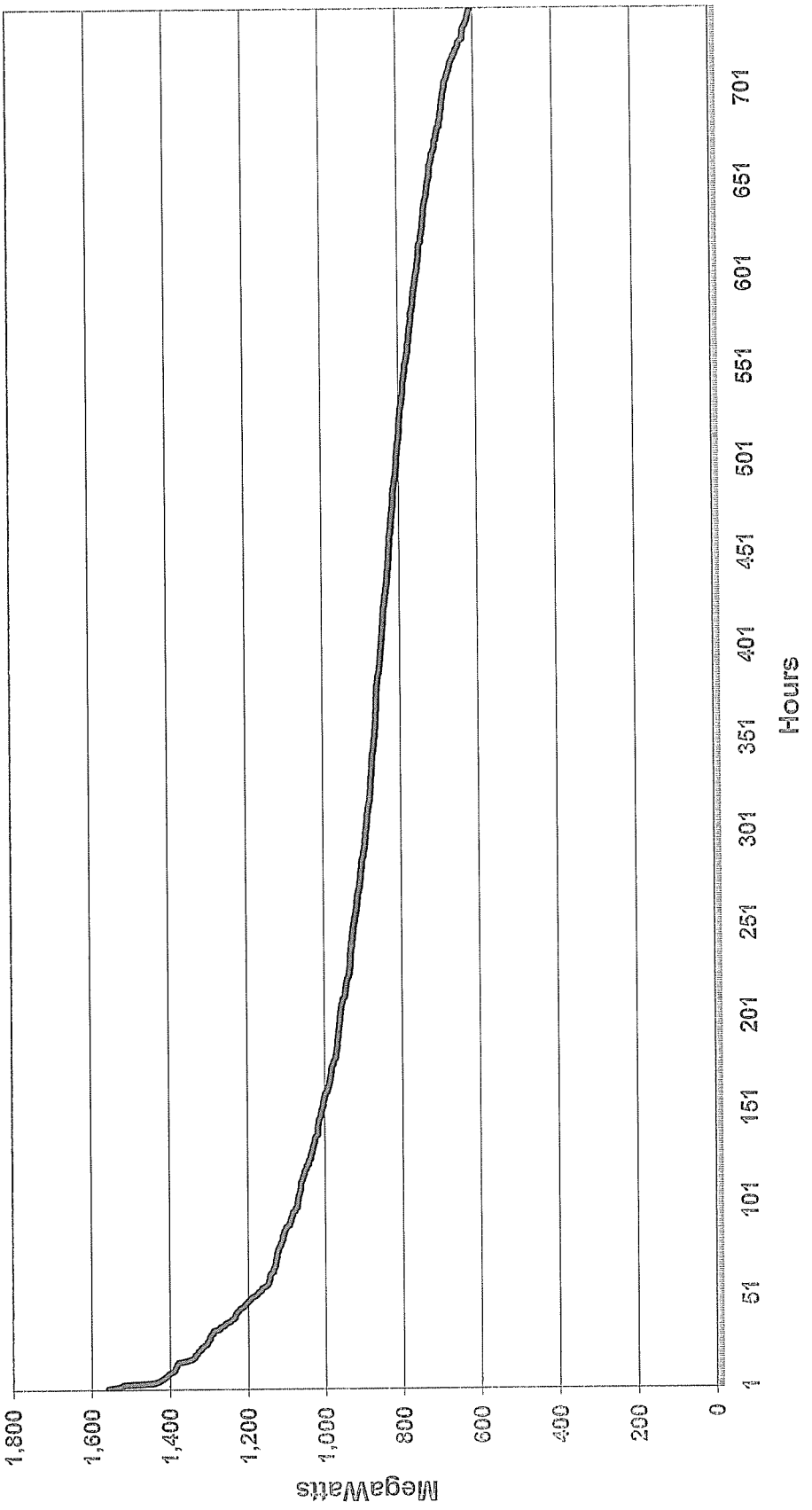
Kentucky Power Company
January 2009 Load Duration Curve
(Internal Load)

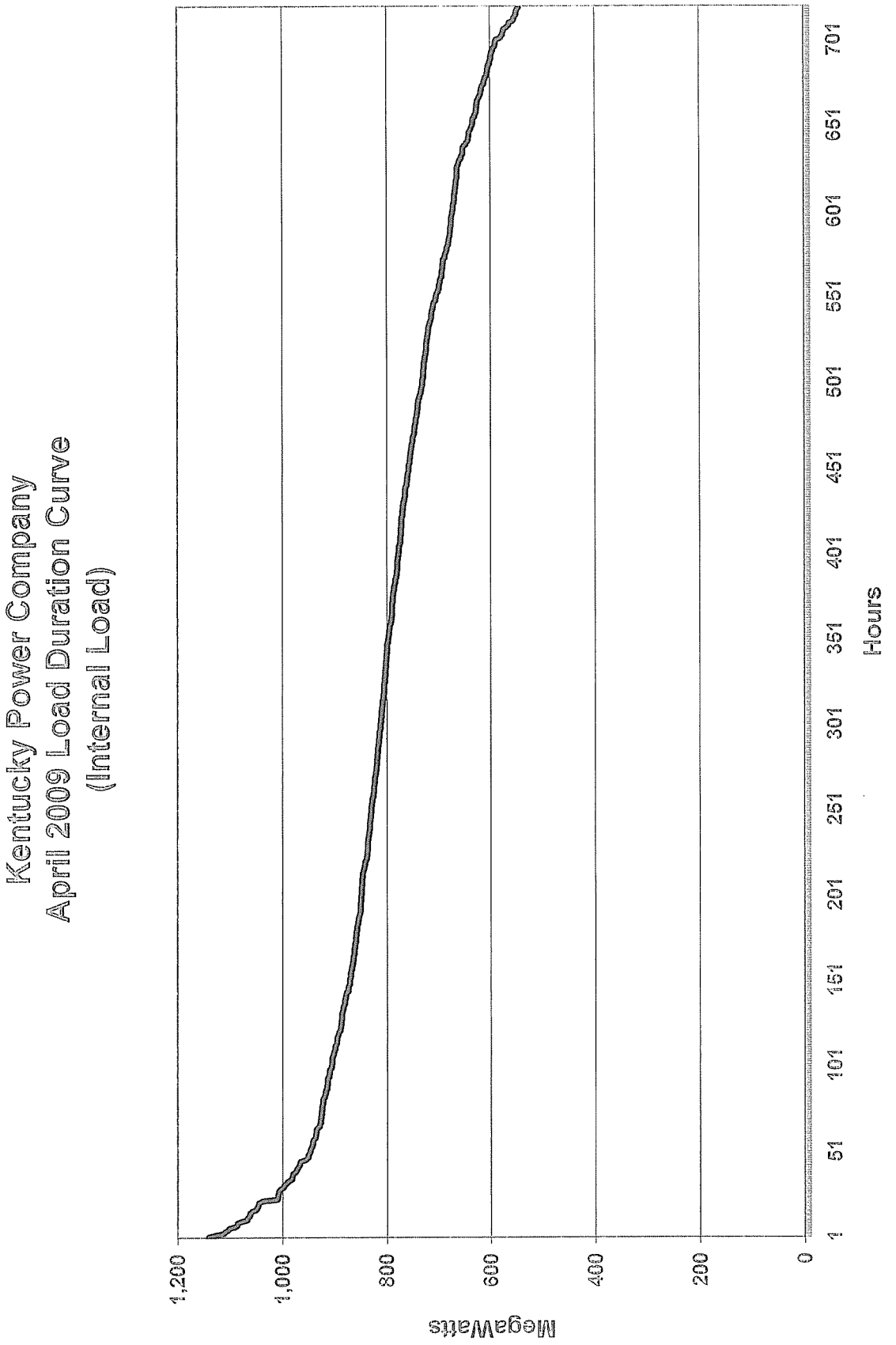


Kentucky Power Company
February 2009 Load Duration Curve
(Internal Load)

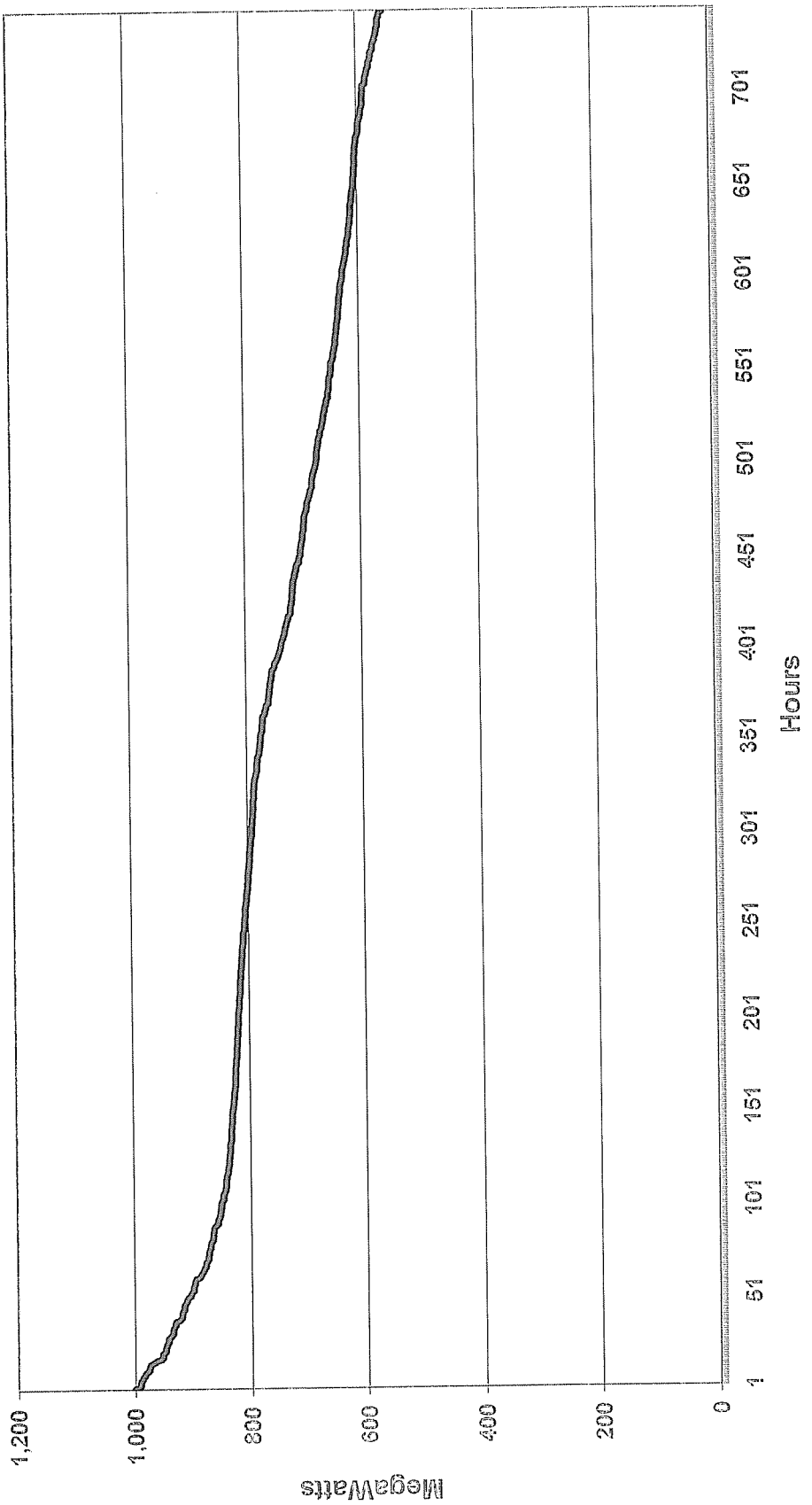


Kentucky Power Company
March 2009 Load Duration Curve
(Internal Load)

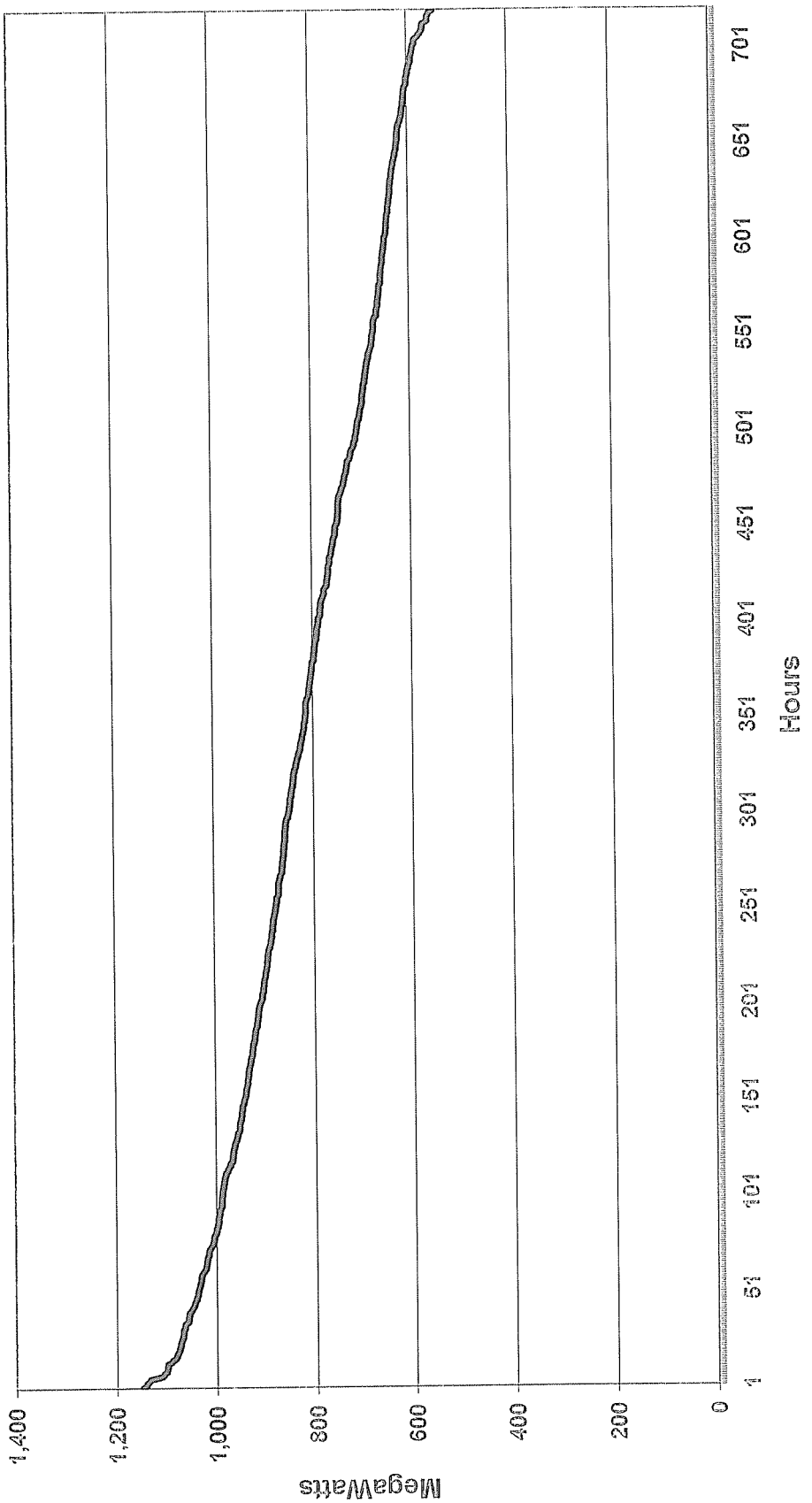



Kentucky Power Company
April 2009 Load Duration Curve
(Internal Load)
MegaWatts
1,200
1,000
800
600
400
200
0
Hours
1
51
101
151
201
251
301
351
401
451
501
551
601
651
701

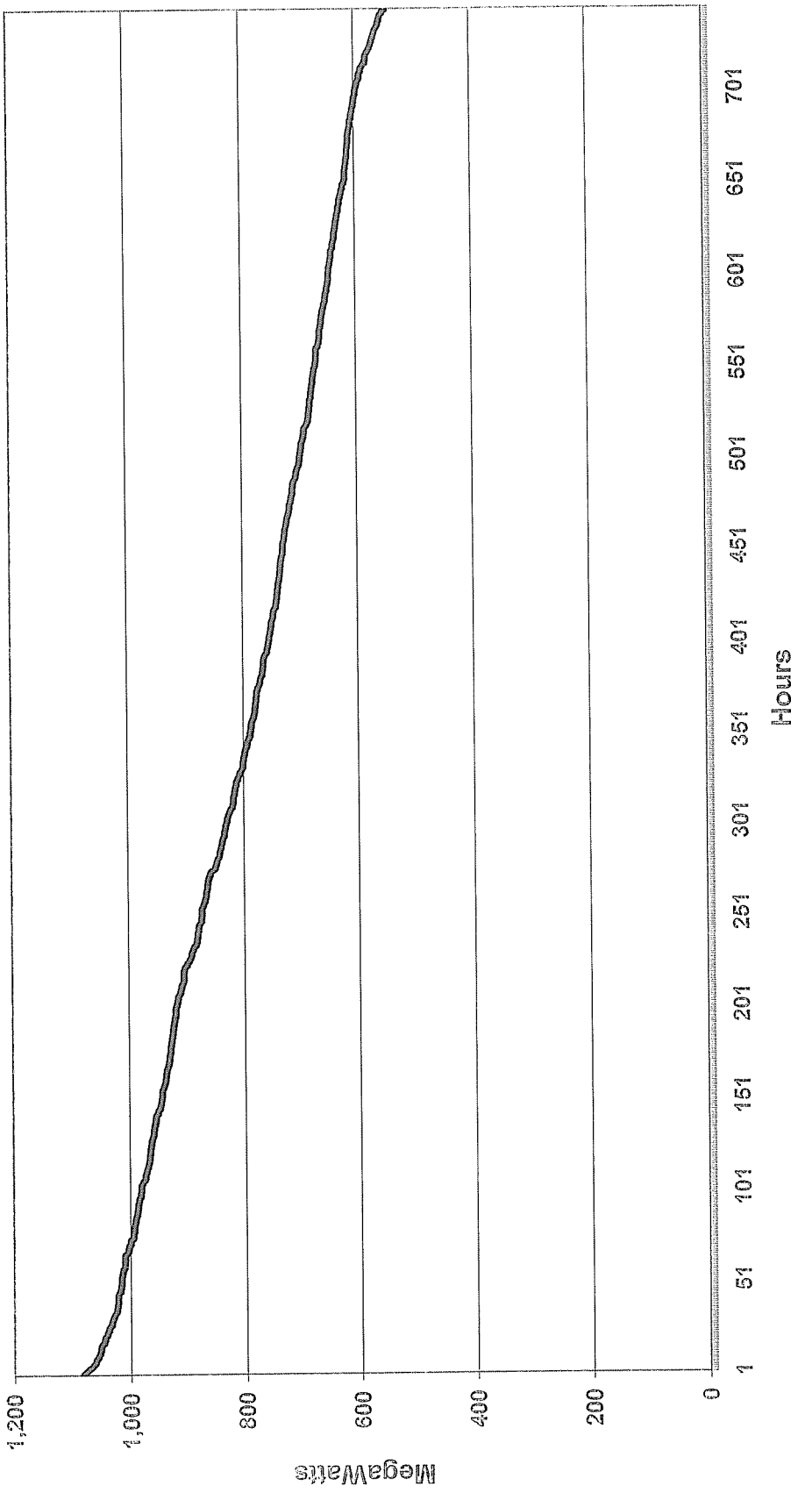
Kentucky Power Company
May 2009 Load Duration Curve
(Internal Load)

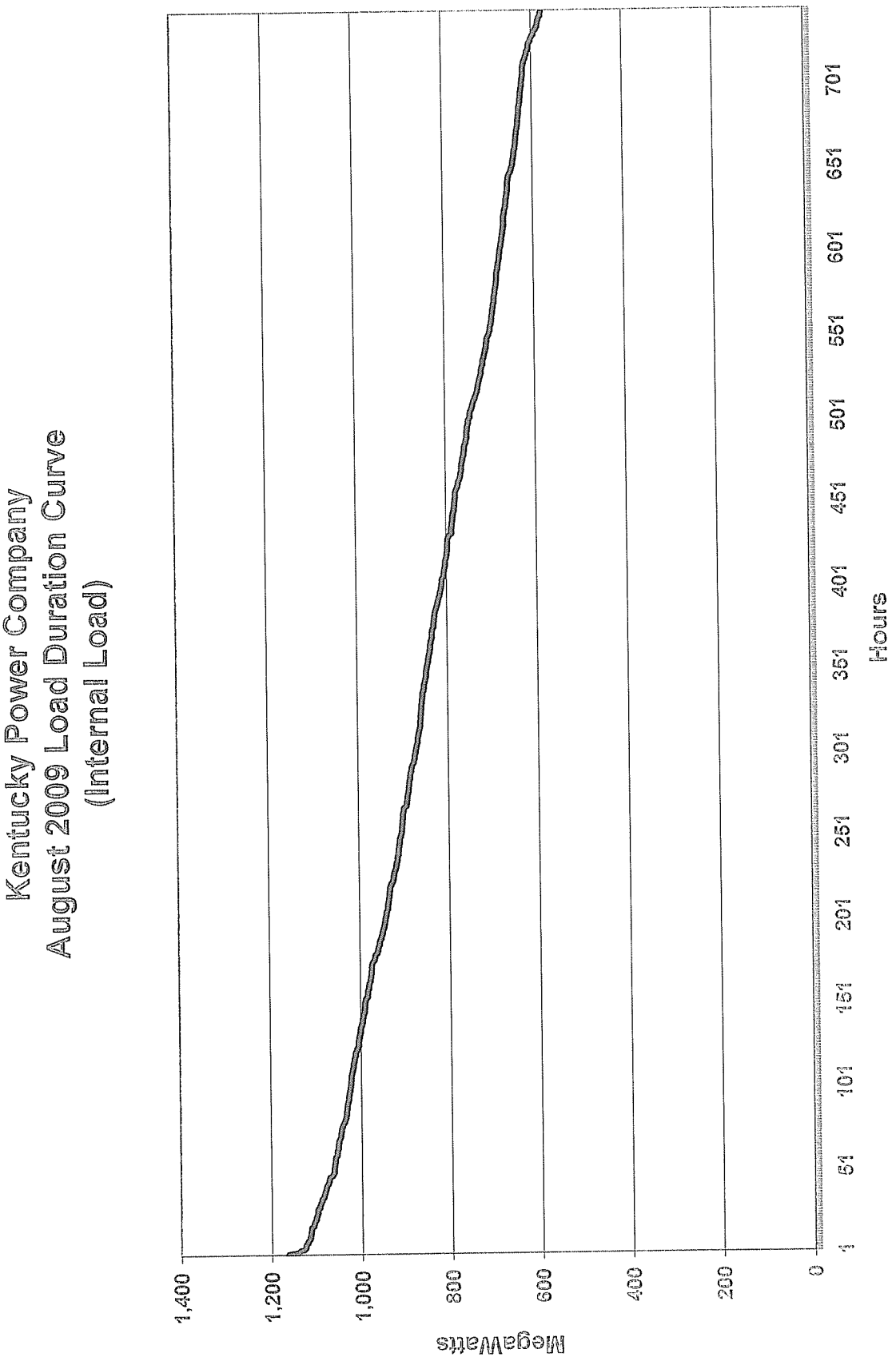


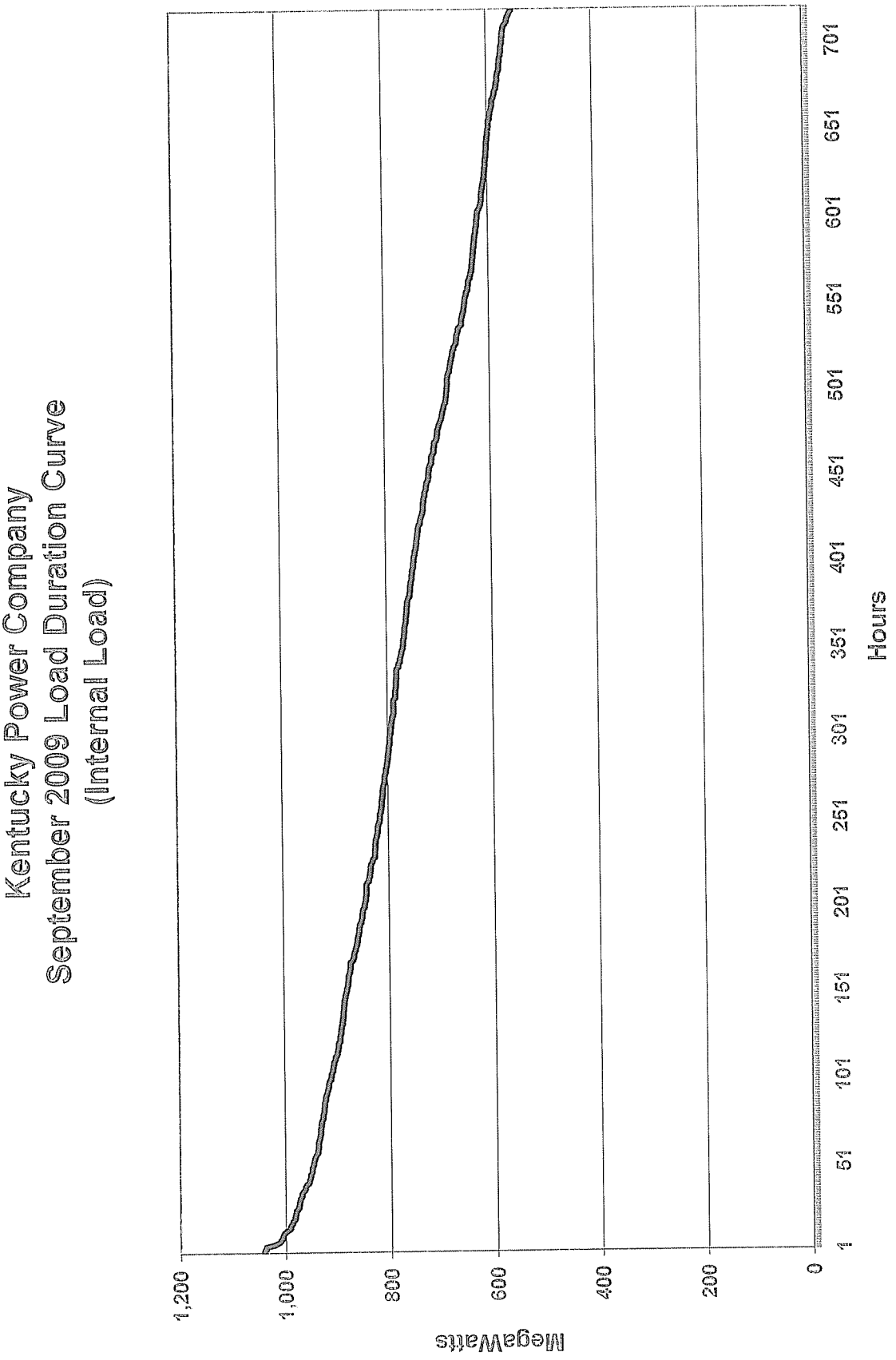
Kentucky Power Company
June 2009 Load Duration Curve
(Internal Load)



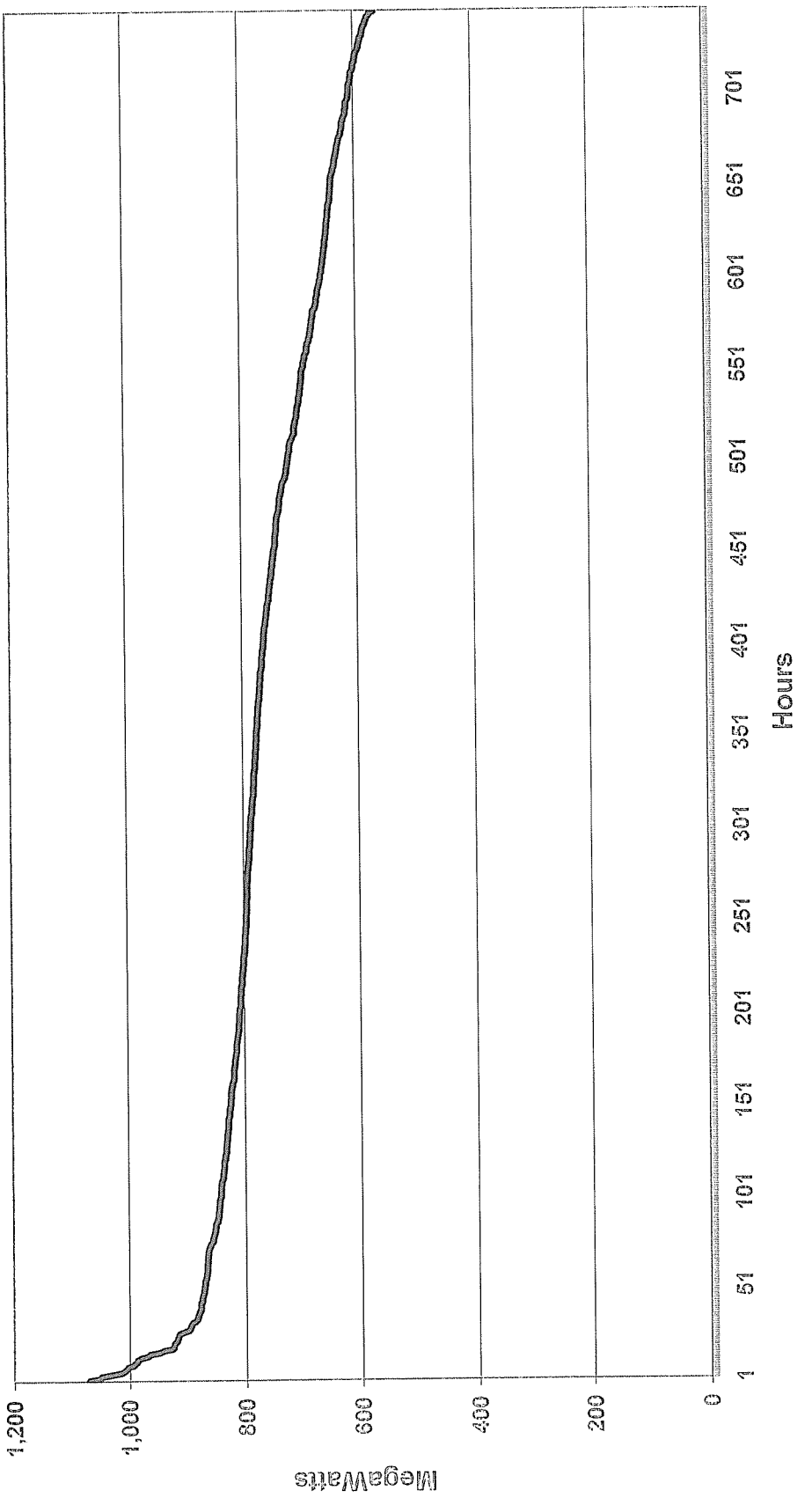
Kentucky Power Company
July 2009 Load Duration Curve
(Internal Load)



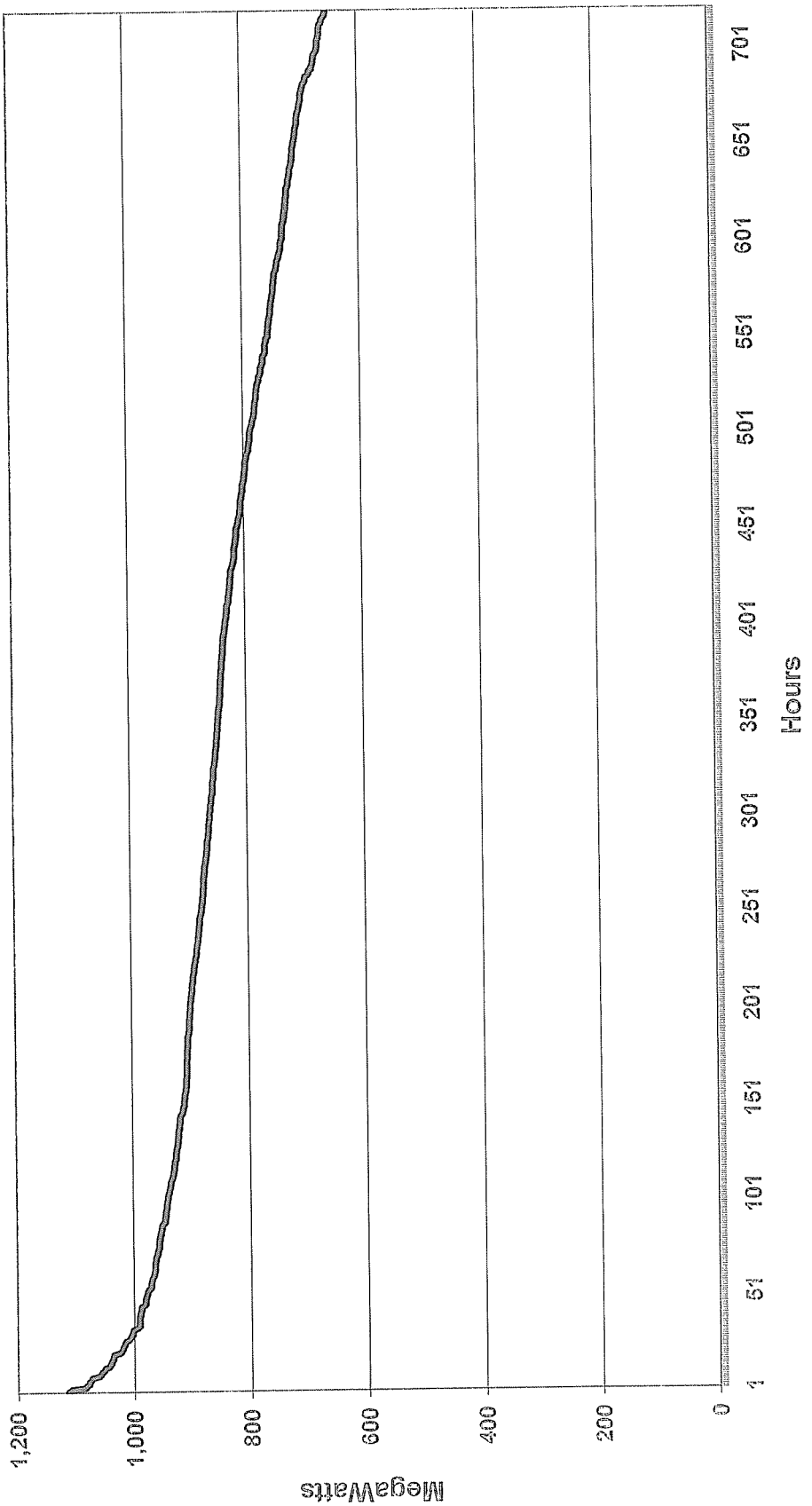

Kentucky Power Company
August 2009 Load Duration Curve
(Internal Load)
MegaWatts
1,400
1,200
1,000
800
600
400
200
0
1
51
101
151
201
251
301
351
401
451
501
551
601
651
701
Hours


Kentucky Power Company
September 2009 Load Duration Curve
(Internal Load)
MegaWatts
1,200
1,000
800
600
400
200
0
1
51
101
151
201
251
301
351
401
451
501
551
601
651
701
Hours

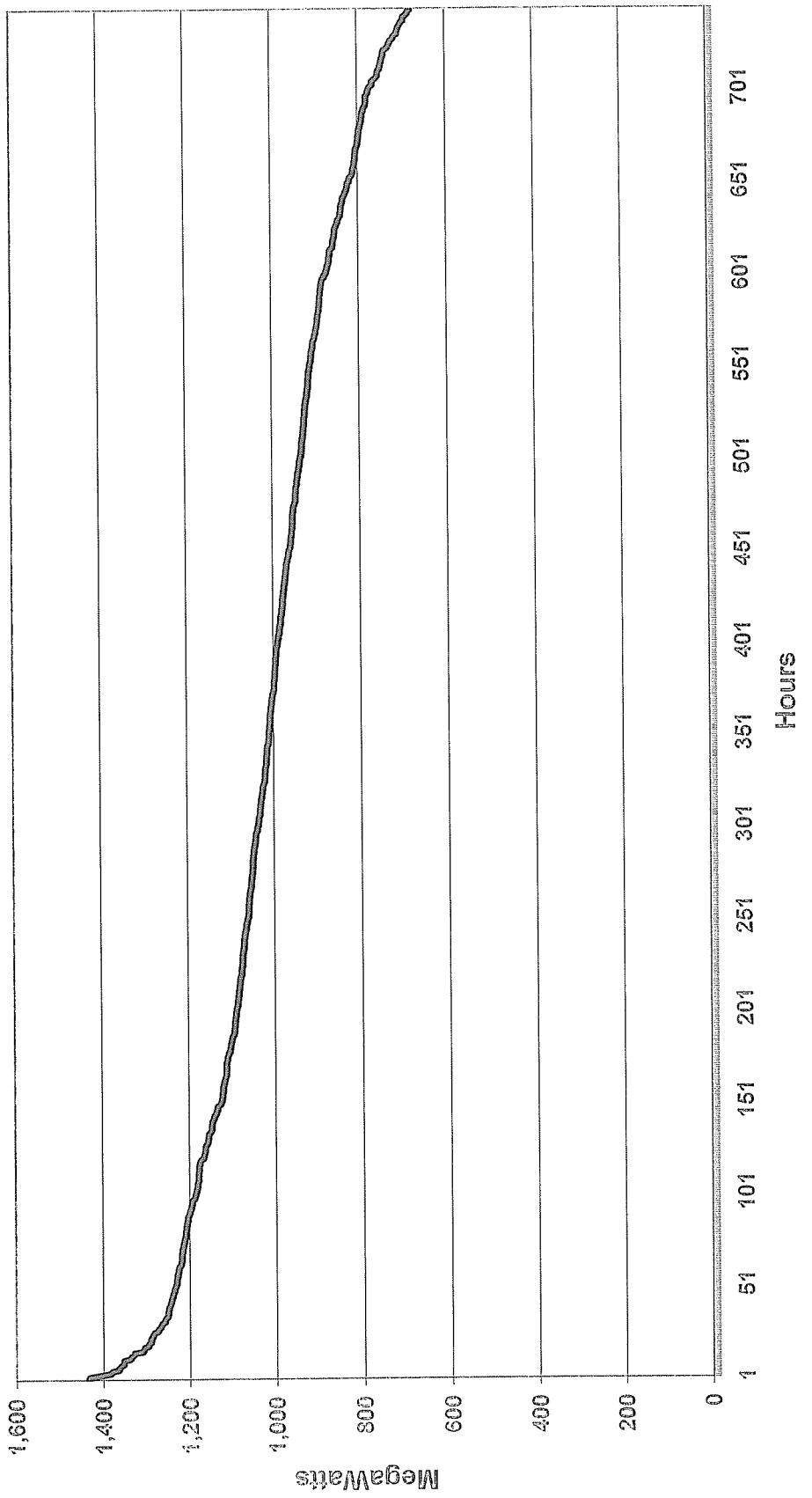
Kentucky Power Company
October 2009 Load Duration Curve
(Internal Load)



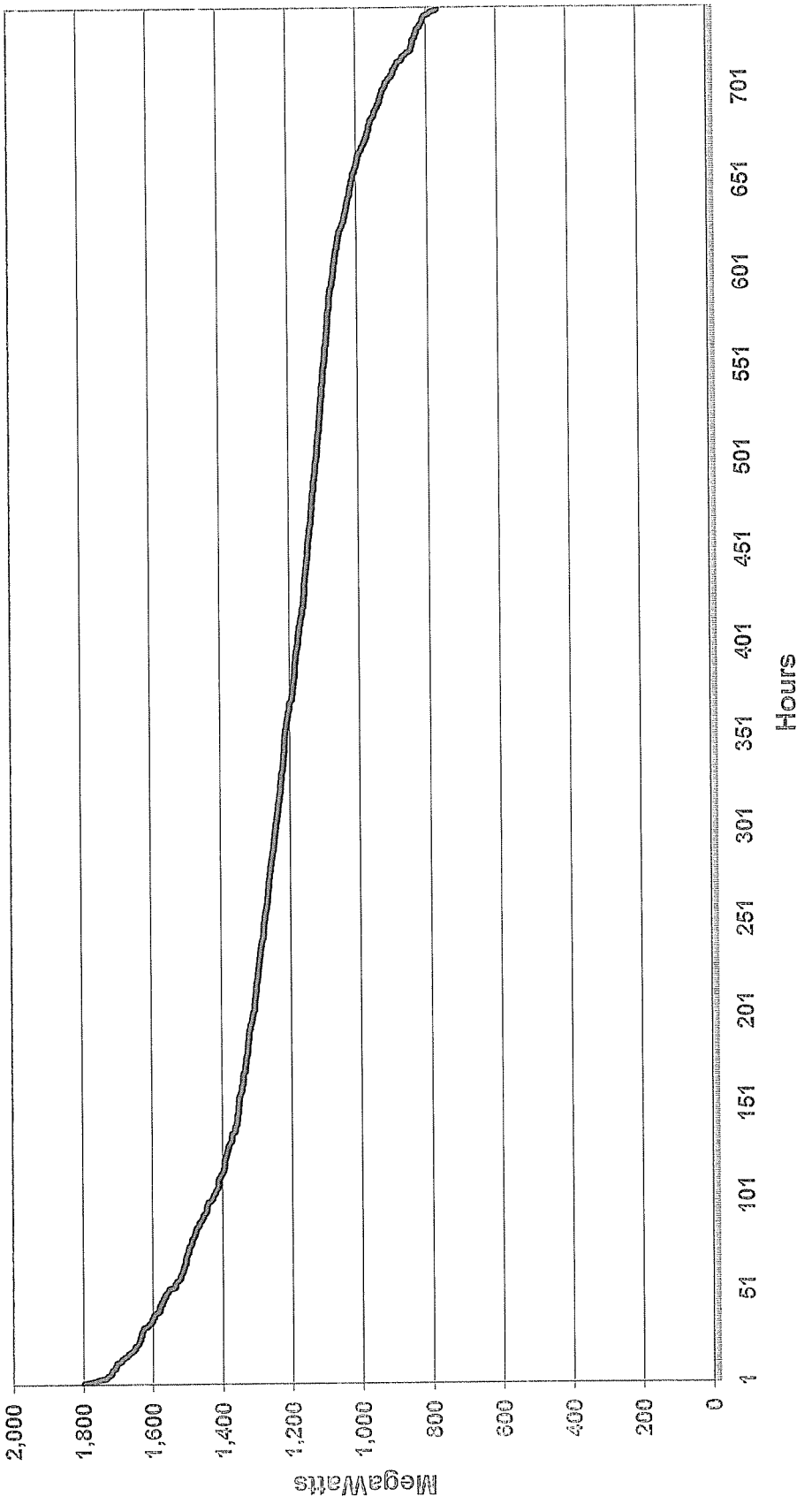
Kentucky Power Company
November 2009 Load Duration Curve
(Internal Load)

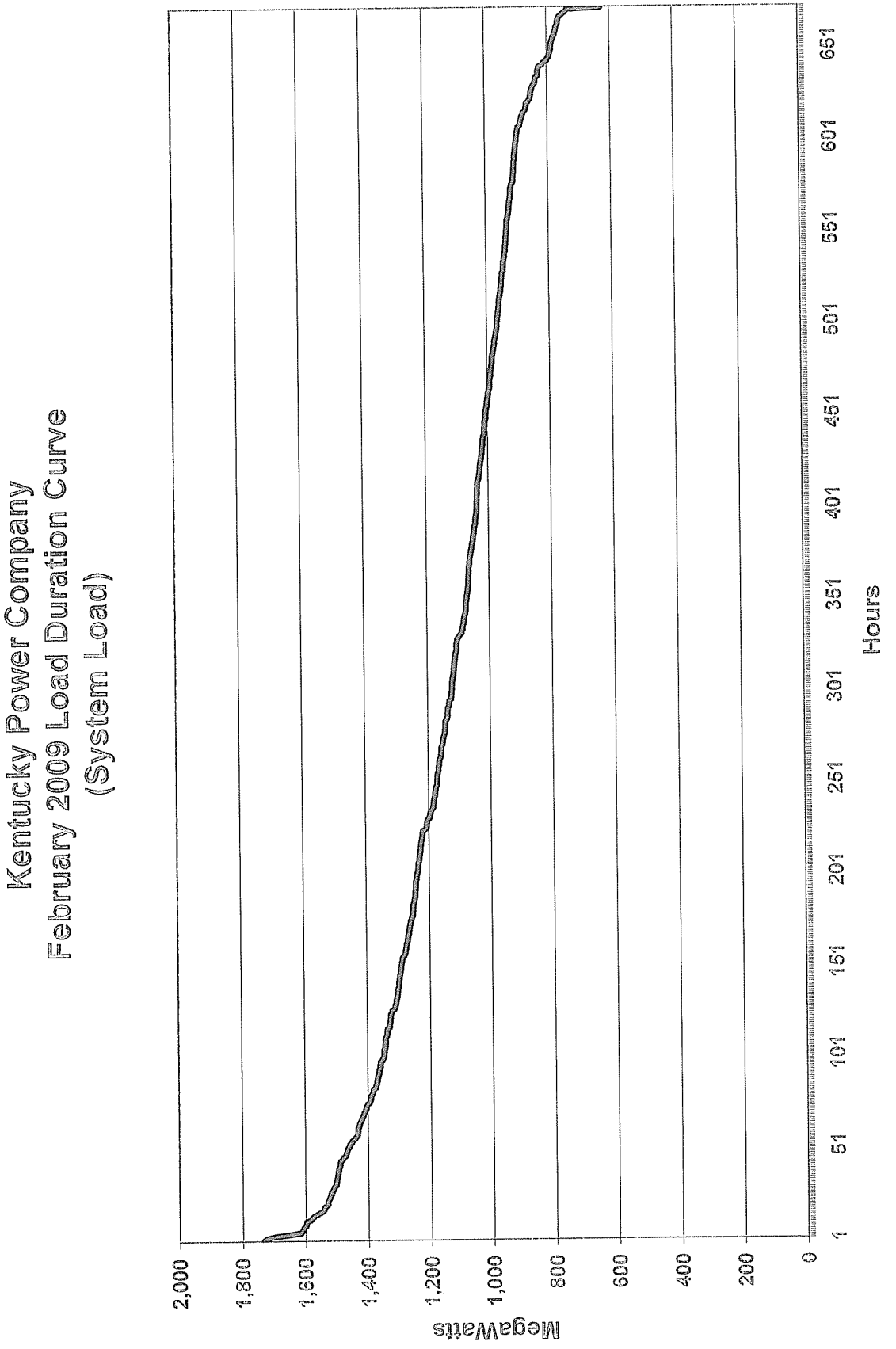


Kentucky Power Company
December 2009 Load Duration Curve
(Internal Load)

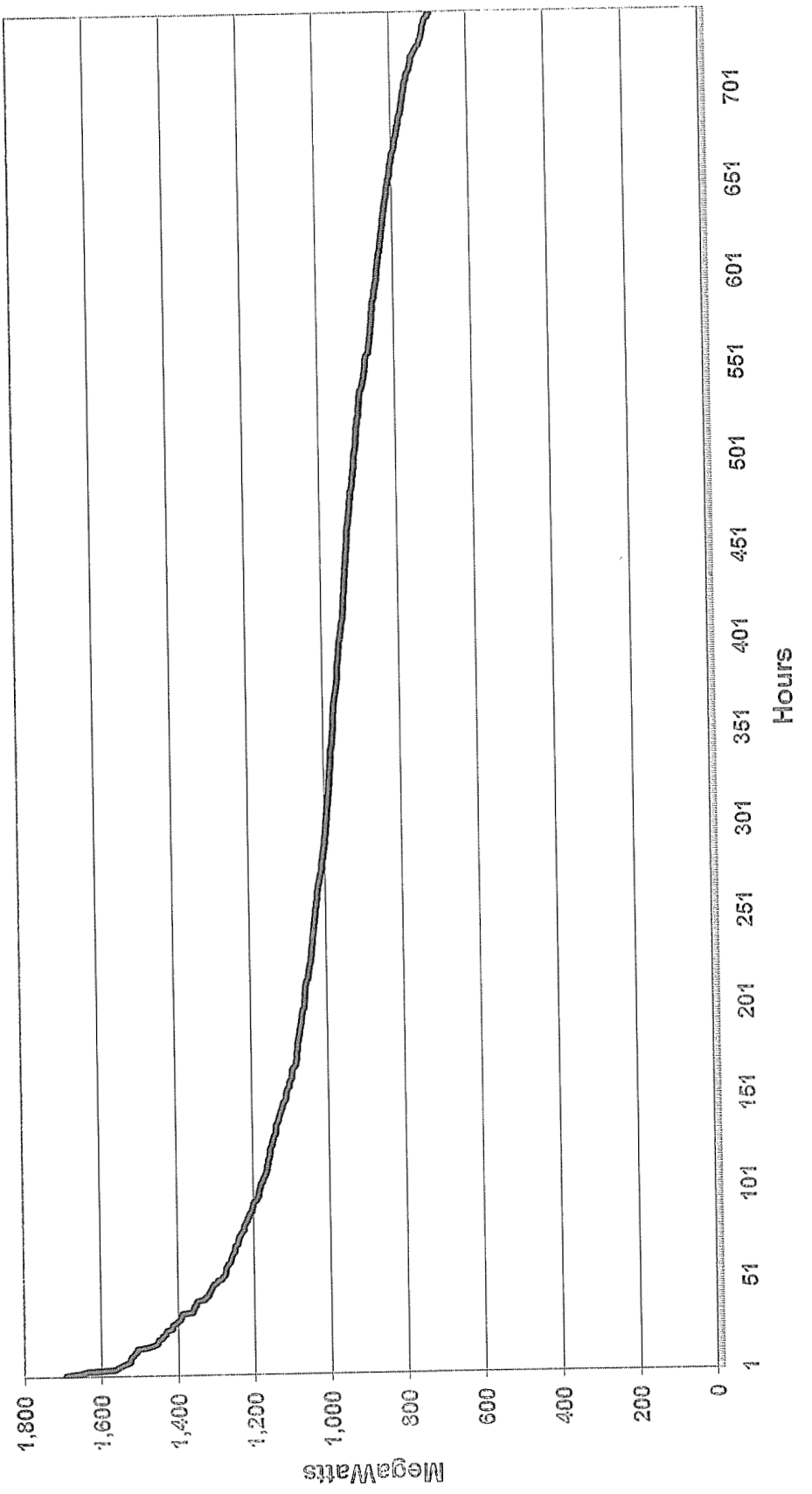


Kentucky Power Company
January 2009 Load Duration Curve
(System Load)

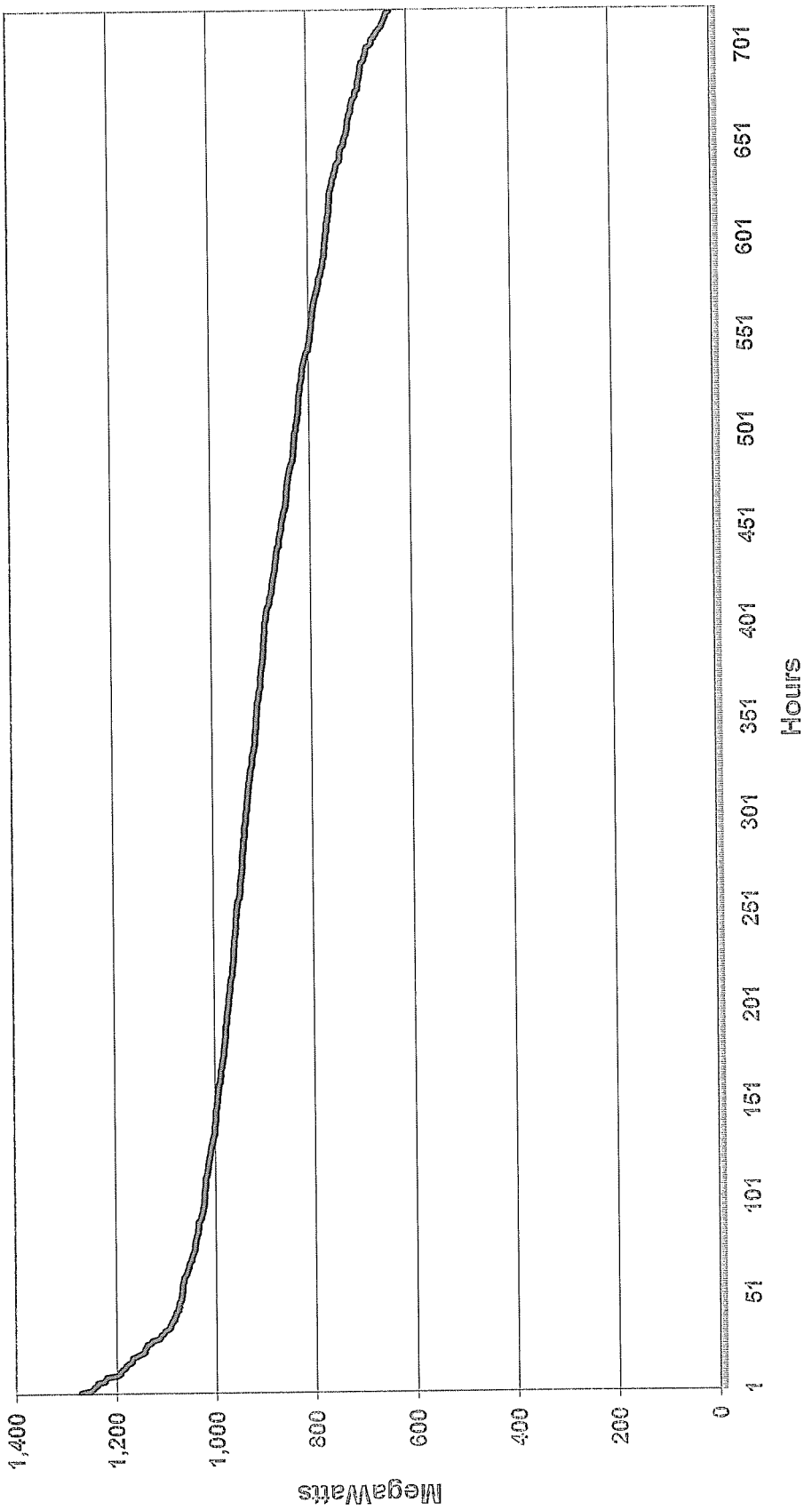



Kentucky Power Company
February 2009 Load Duration Curve
(System Load)
MegaWatts
2,000
1,800
1,600
1,400
1,200
1,000
800
600
400
200
0
1
51
101
151
201
251
301
351
401
451
501
551
601
651
Hours

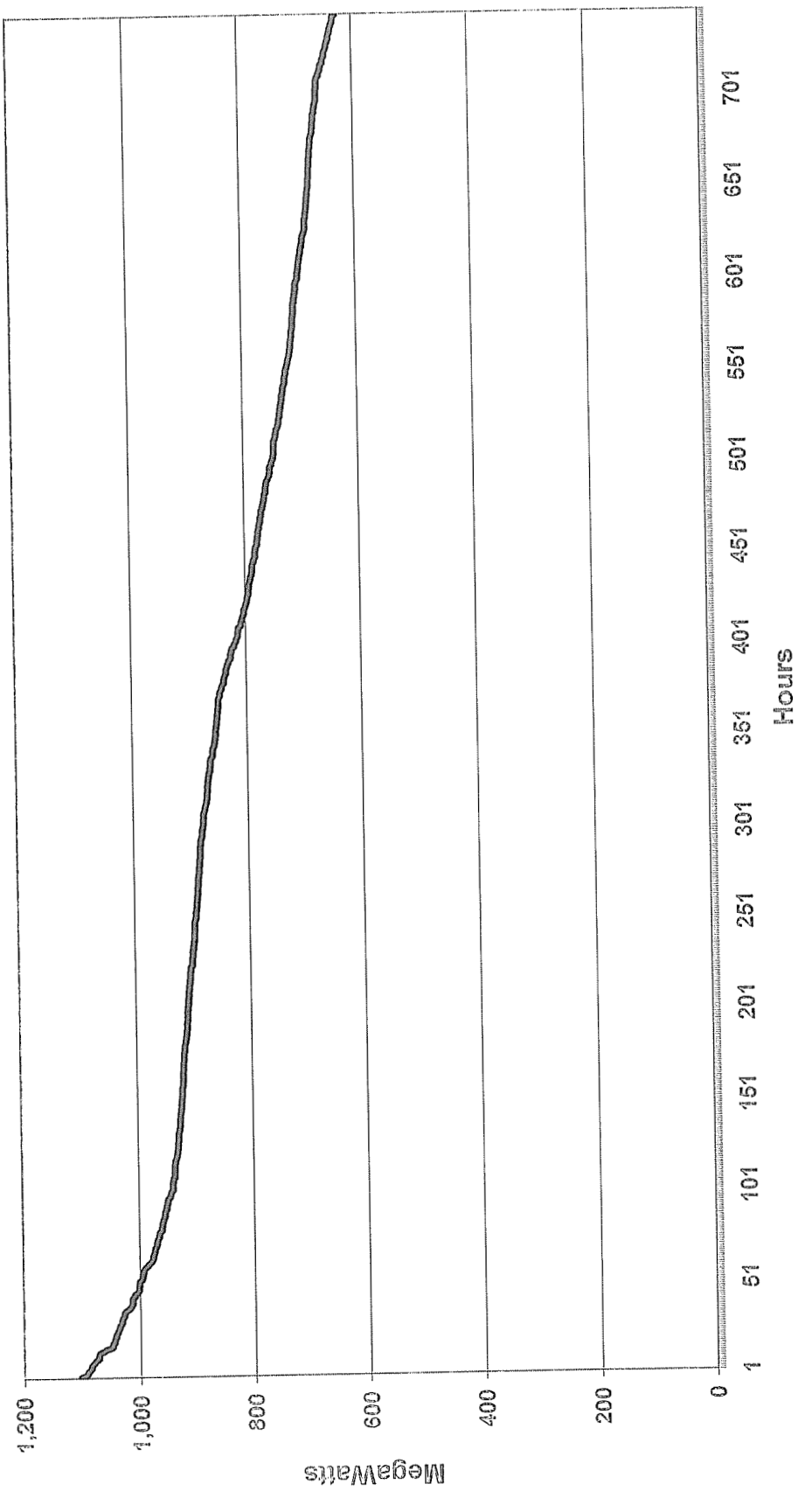
Kentucky Power Company
March 2009 Load Duration Curve
(System Load)

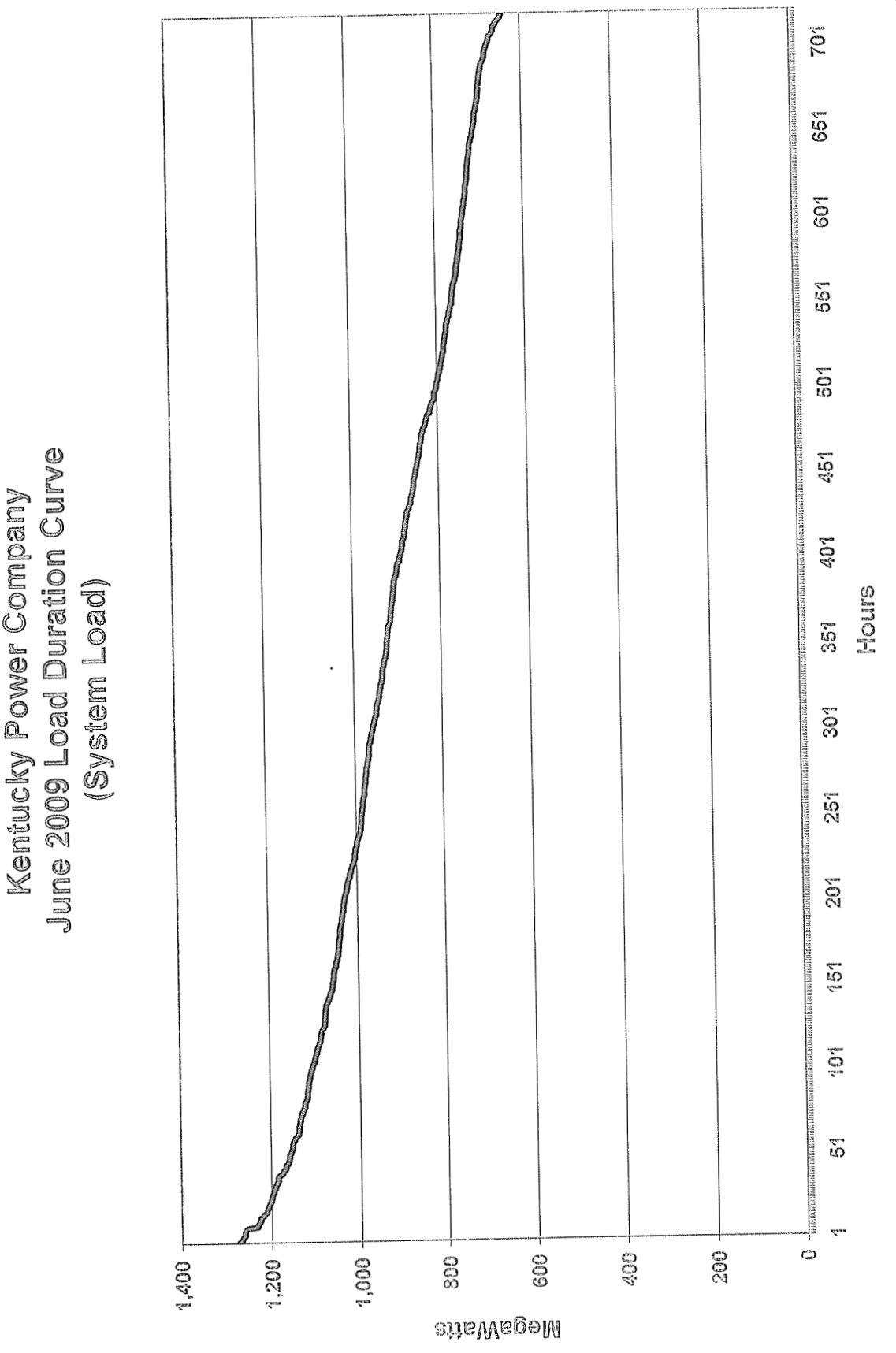


Kentucky Power Company
April 2009 Load Duration Curve
(System Load)

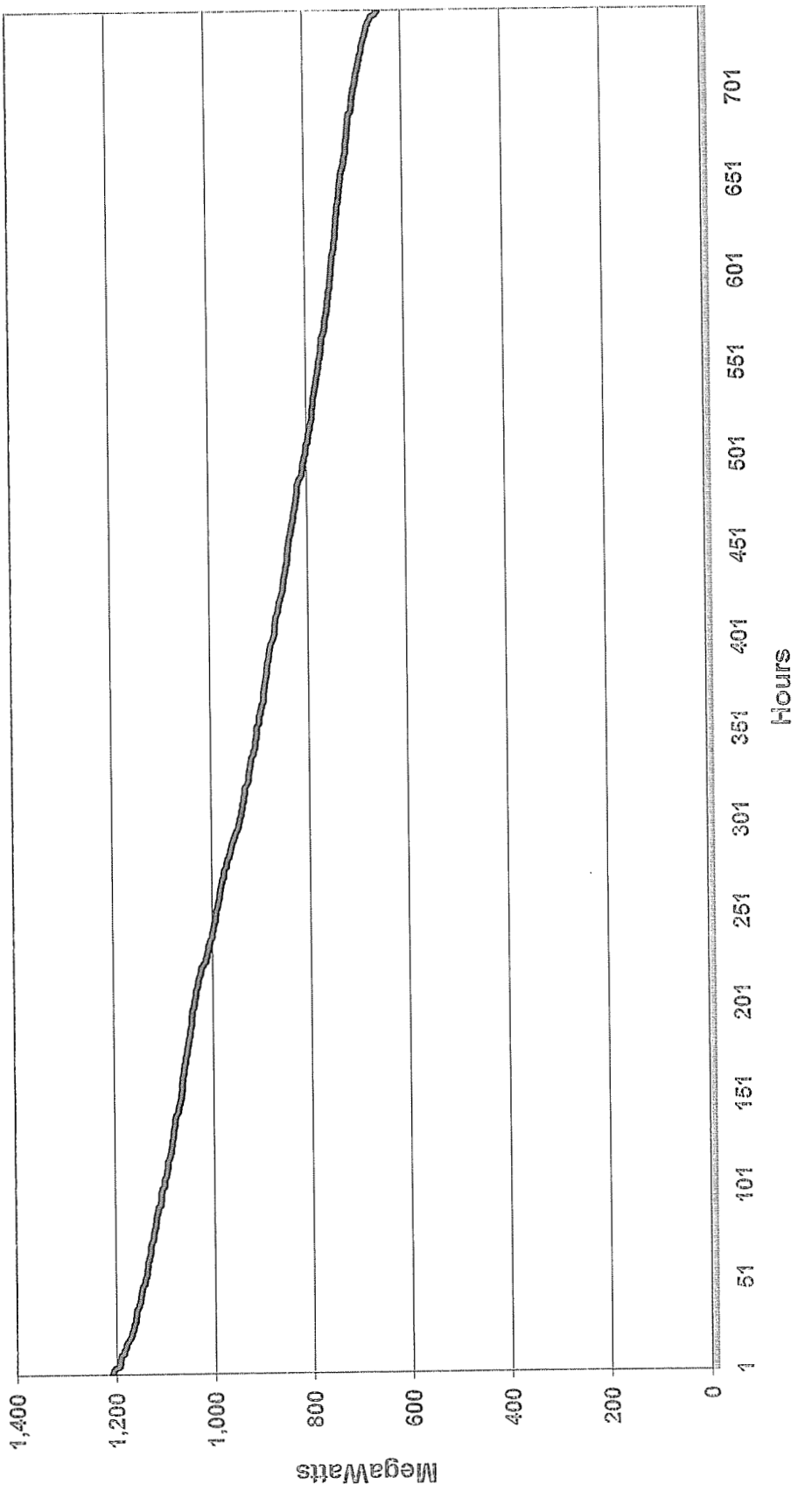


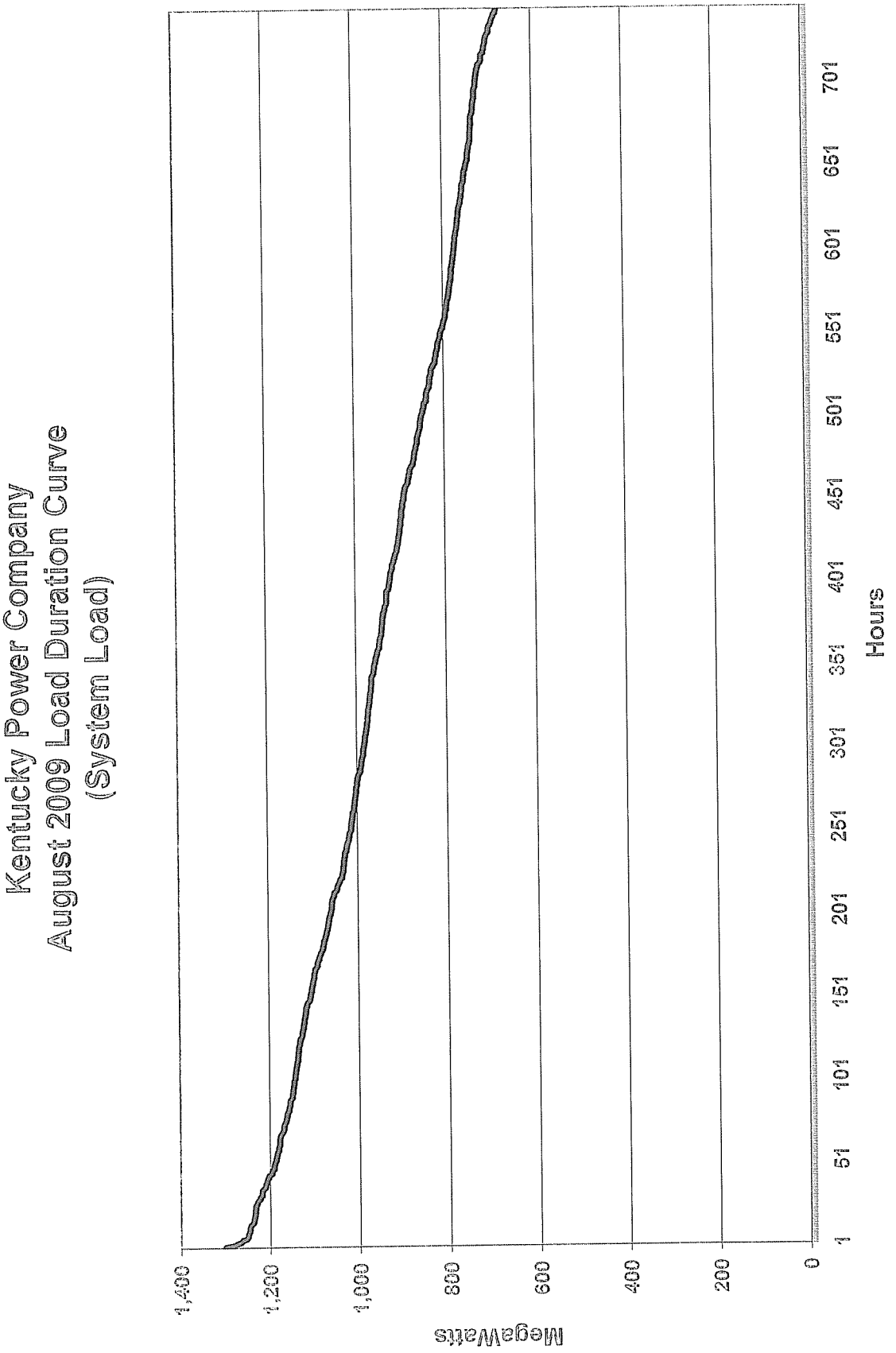
Kentucky Power Company
May 2009 Load Duration Curve
(System Load)




Kentucky Power Company
June 2009 Load Duration Curve
(System Load)
MegaWatts
1,400
1,200
1,000
800
600
400
200
0
1
51
101
151
201
251
301
351
401
451
501
551
601
651
701
Hours

Kentucky Power Company
July 2009 Load Duration Curve
(System Load)




Kentucky Power Company
August 2009 Load Duration Curve
(System Load)
MegaWatts
1,400
1,200
1,000
800
600
400
200
0
1
51
101
151
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251
301
351
401
451
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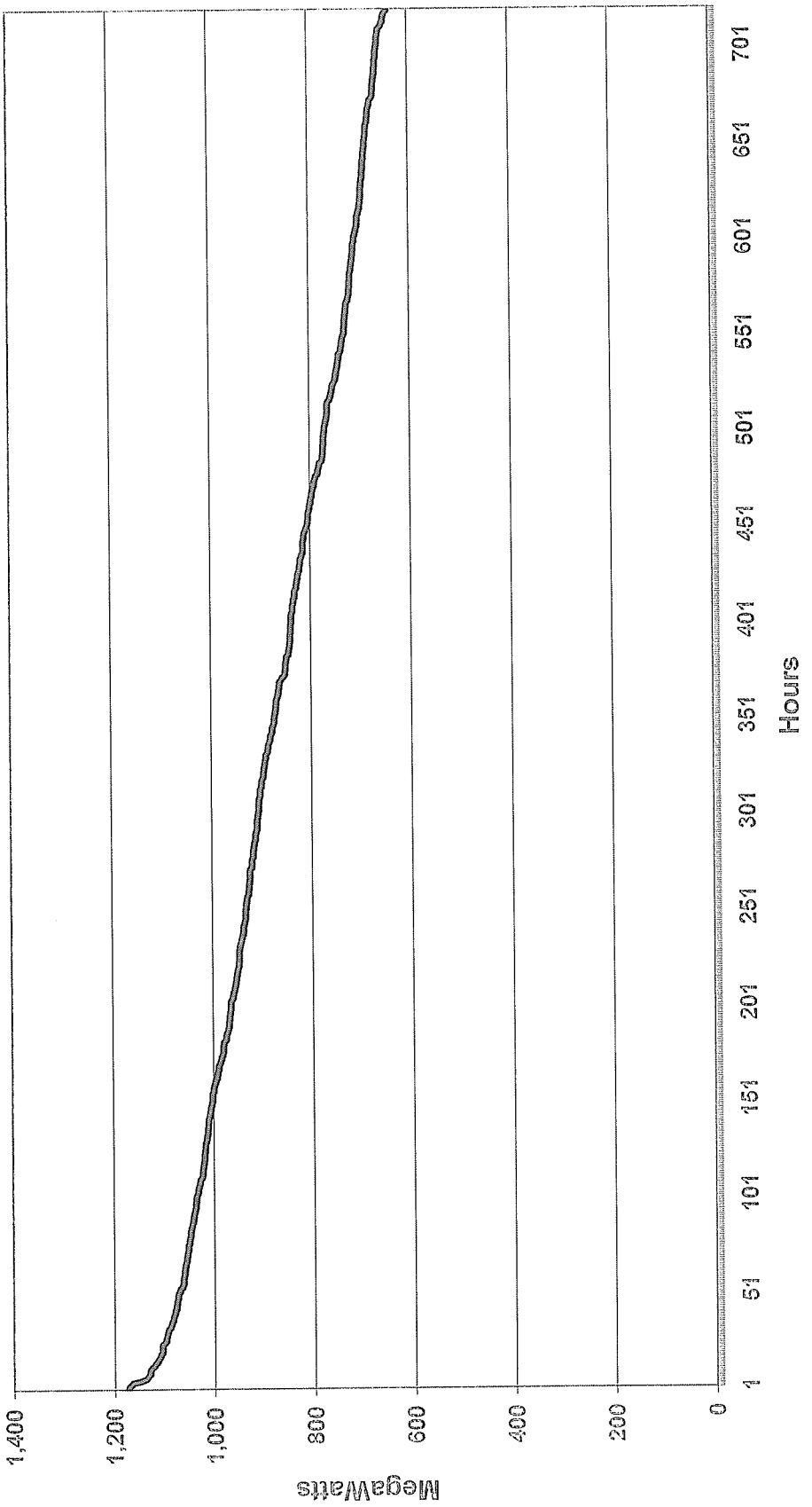
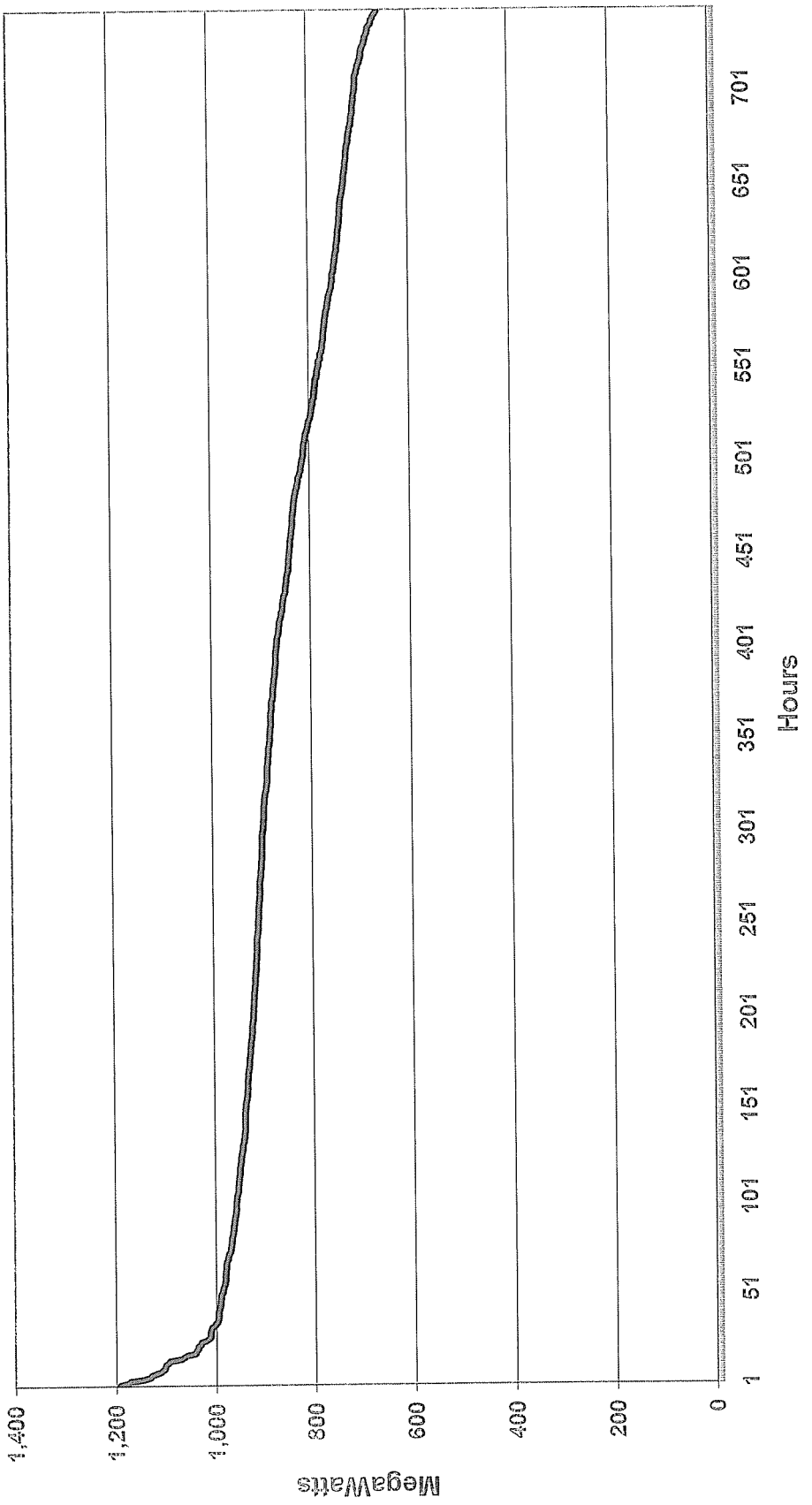
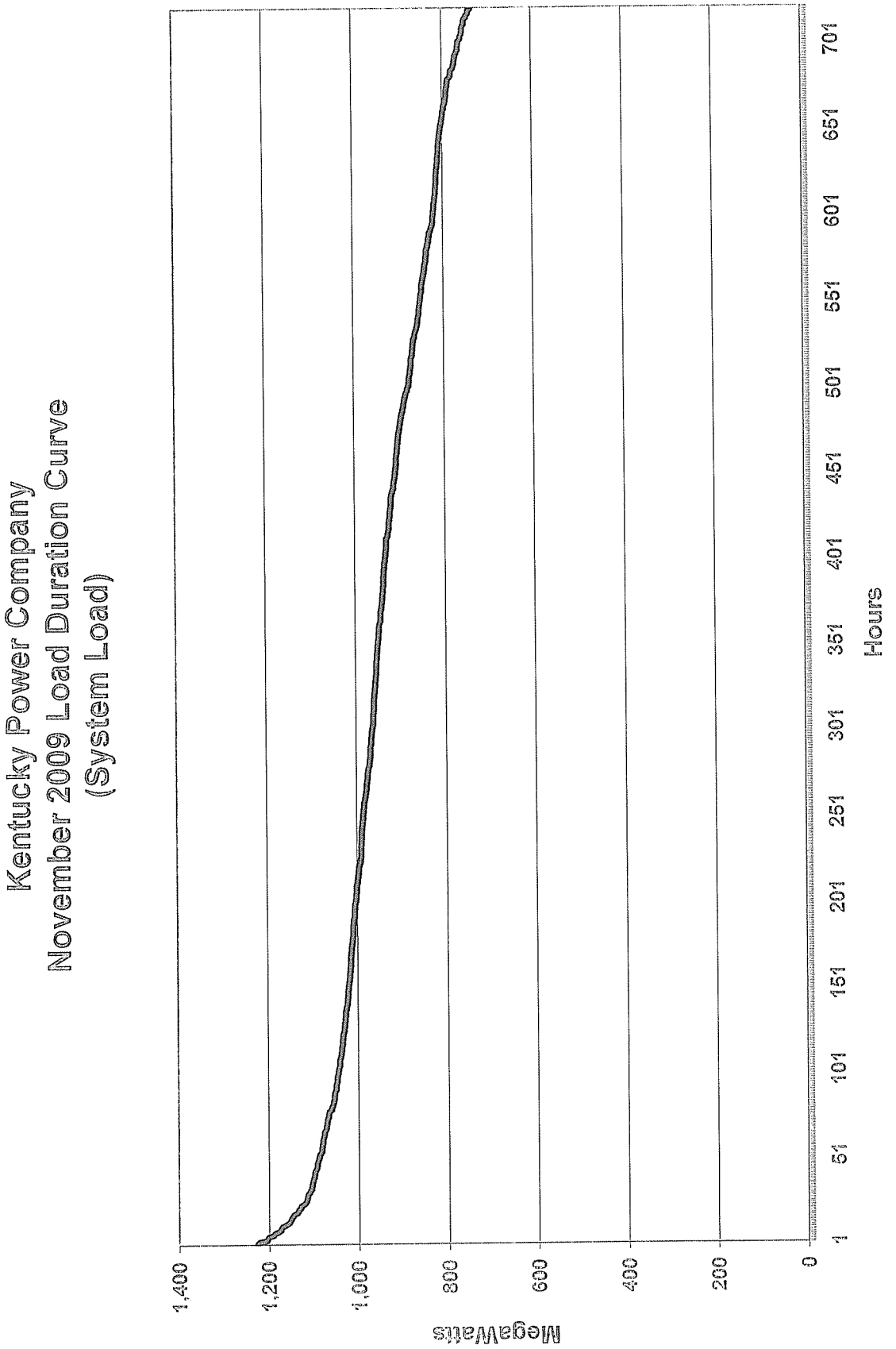
551
601
651
701
Hours

Kentucky Power Company
September 2009 Load Duration Curve
(System Load)



Kentucky Power Company
October 2009 Load Duration Curve
(System Load)




Kentucky Power Company
November 2009 Load Duration Curve
(System Load)
MegaWatts
1,400
1,200
1,000
800
600
400
200
0
1
51
101
151
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251
301
351
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451
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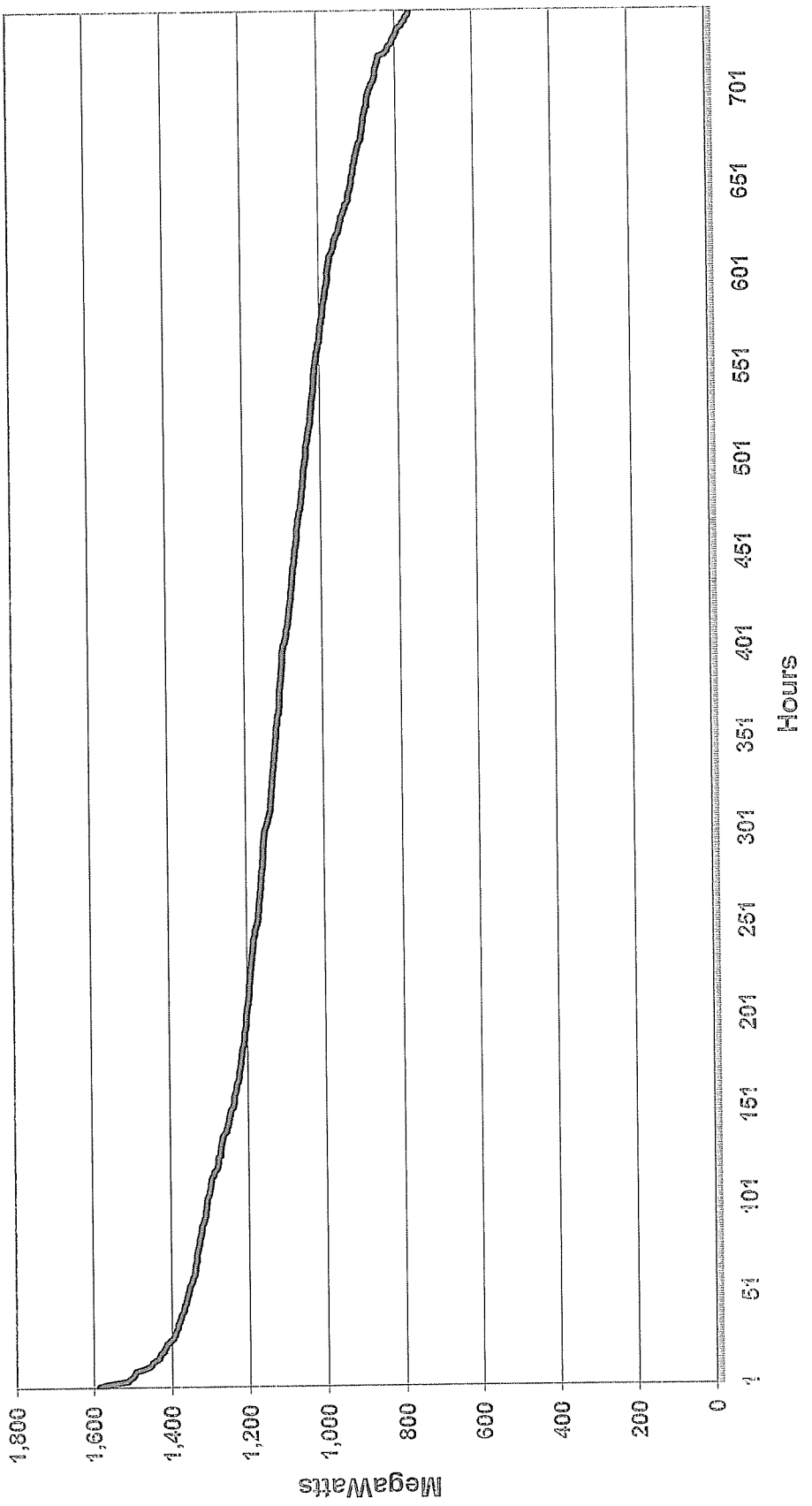
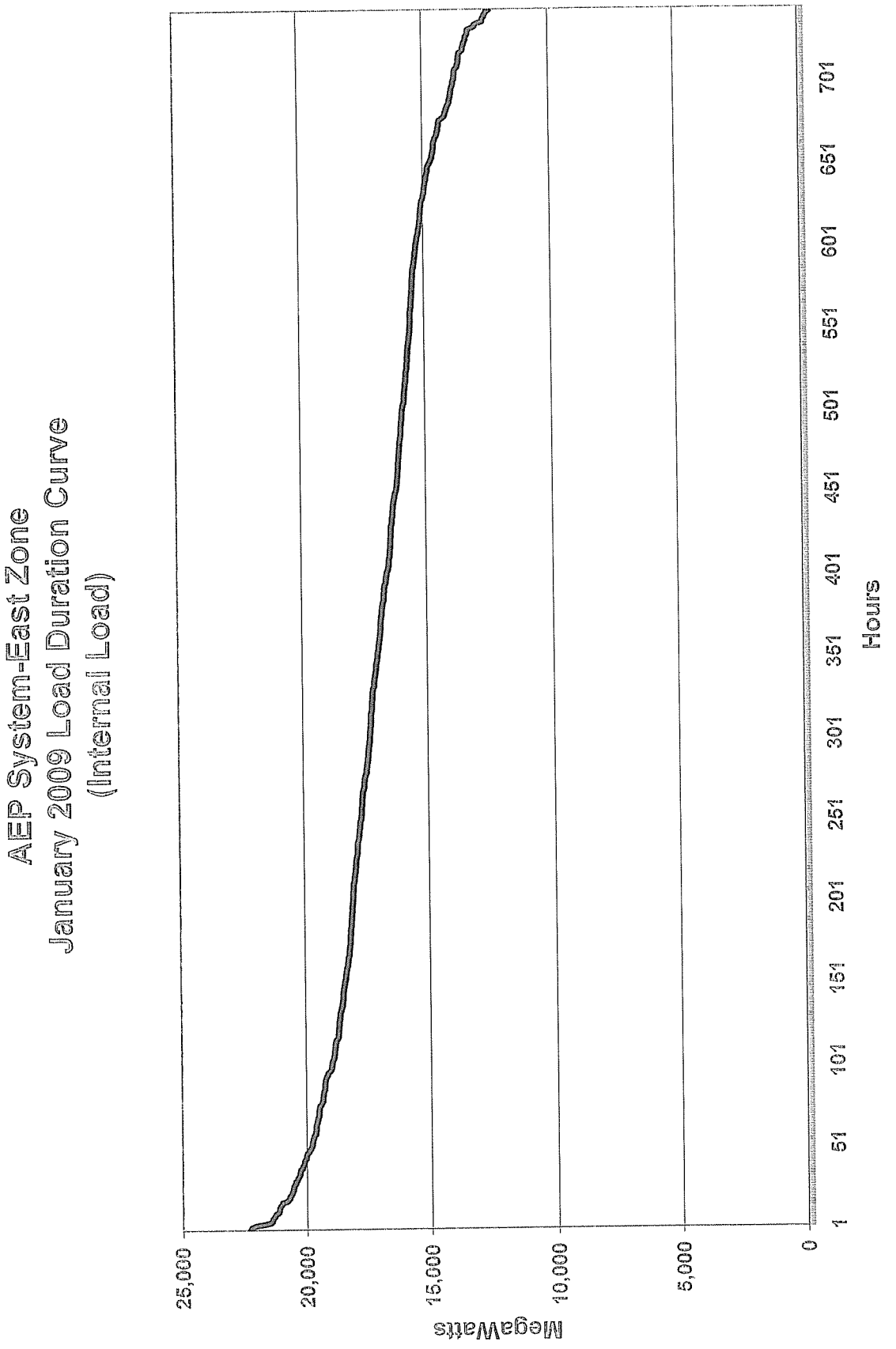
551
601
651
701
Hours

Kentucky Power Company
December 2009 Load Duration Curve
(System Load)




AEP System-East Zone
January 2009 Load Duration Curve
(Internal Load)
MegaWatts
25,000
20,000
15,000
10,000
5,000
0
Hours
1
51
101
151
201
251
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351
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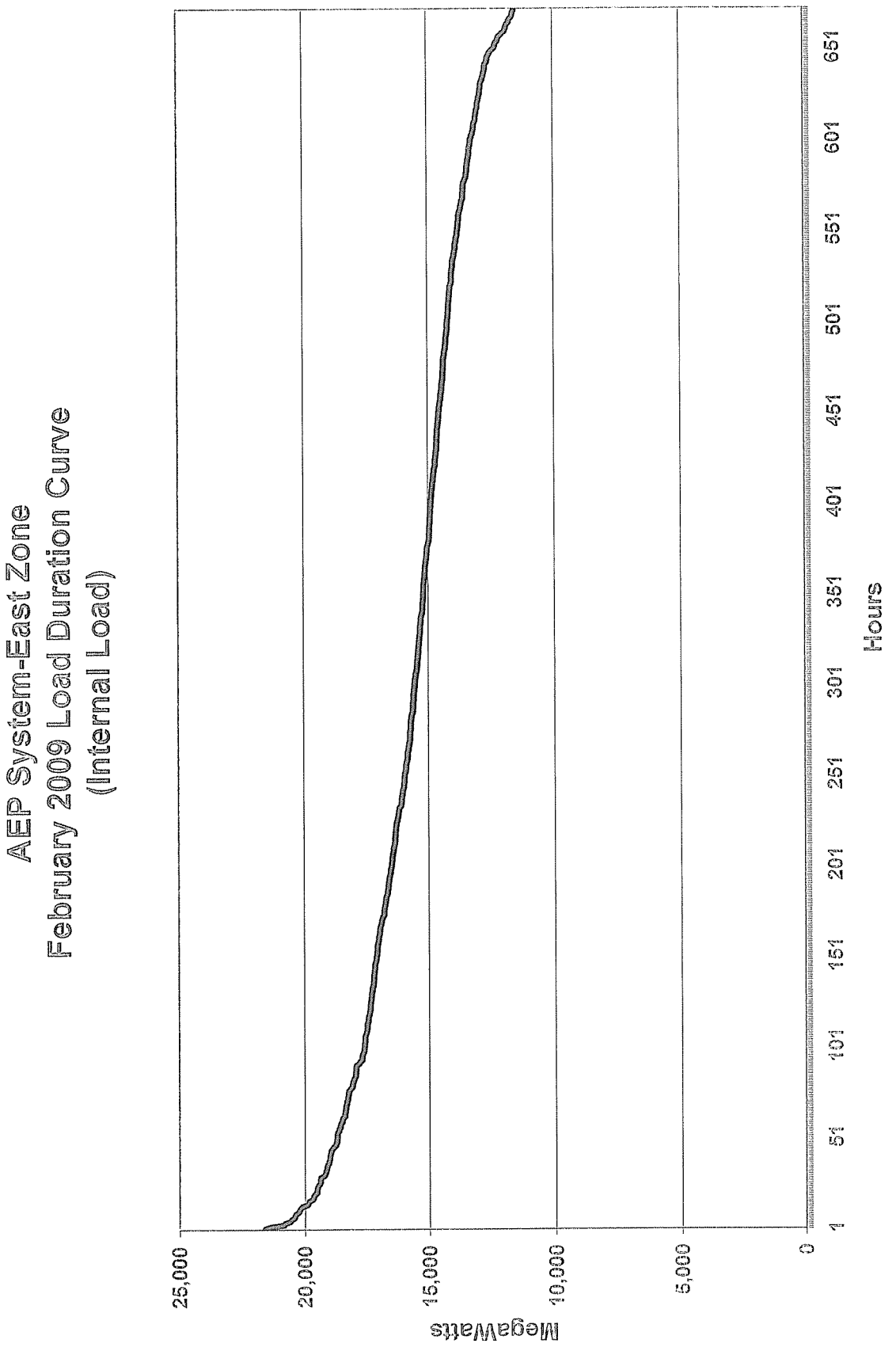
651
701


AEP System-East Zone
February 2009 Load Duration Curve
(Internal Load)
MegaWatts
25,000
20,000
15,000
10,000
5,000
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Hours
1
51
101
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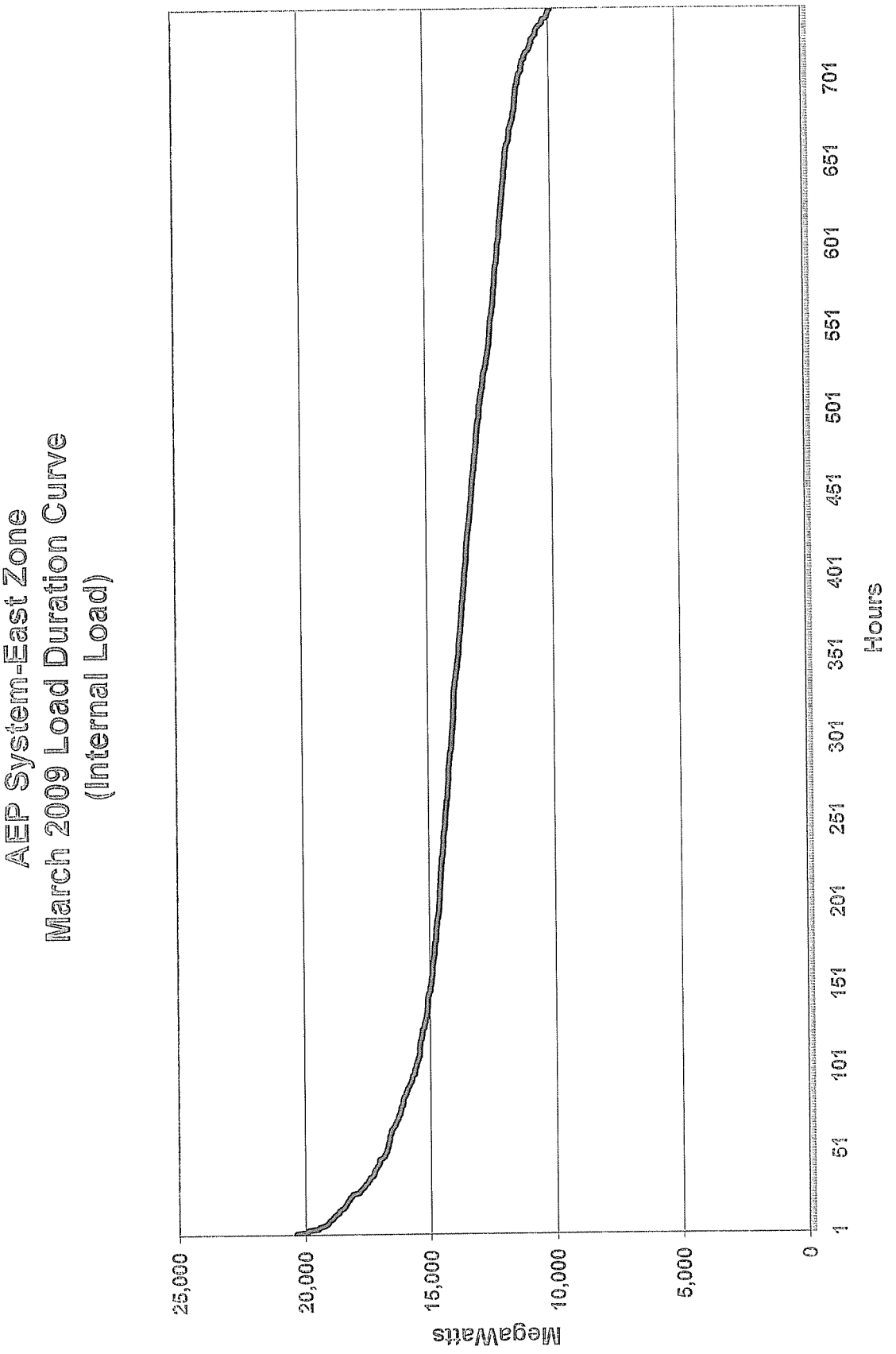
AEP System-East Zone
March 2009 Load Duration Curve
(Internal Load)
MegaWatts
25,000
20,000
15,000
10,000
5,000
0
Hours
1
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101
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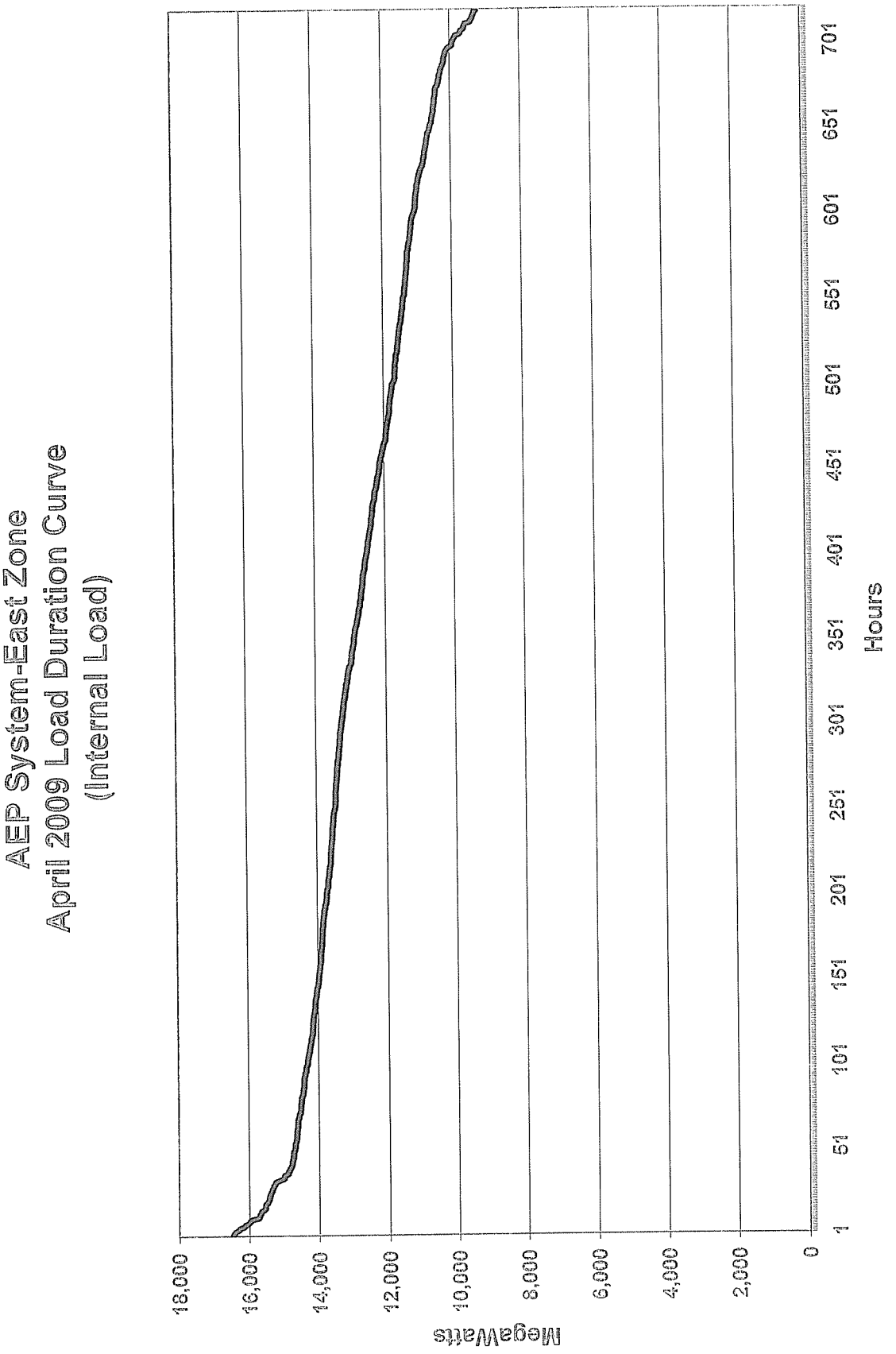
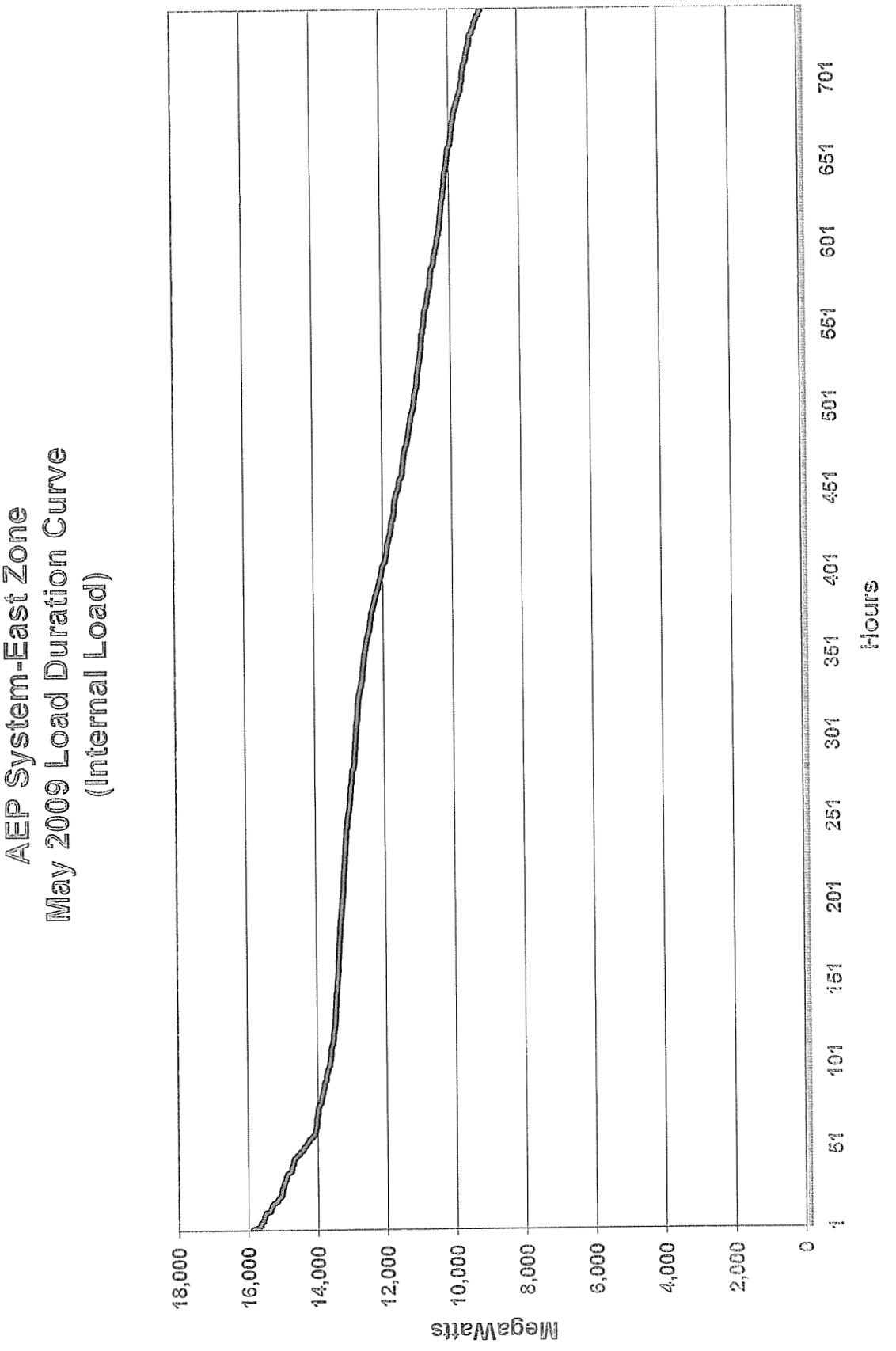
651
701


AEP System-East Zone
April 2009 Load Duration Curve
(Internal Load)
MegaWatts
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
1
51
101
151
201
251
301
351
401
451
501
551
601
651
701
Hours


AEP System-East Zone
May 2009 Load Duration Curve
(Internal Load)
MegaWatts
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
Hours
1
51
101
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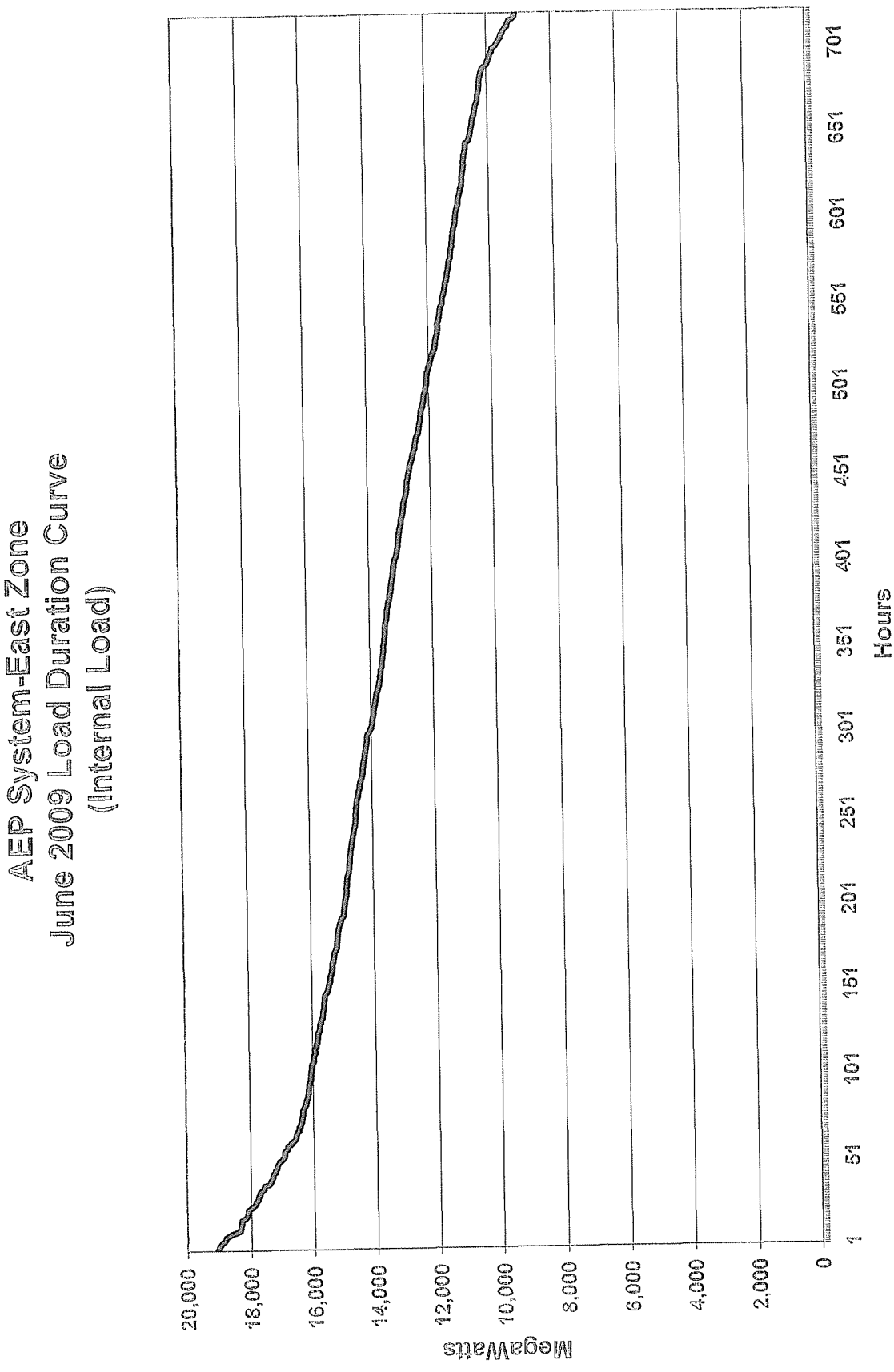
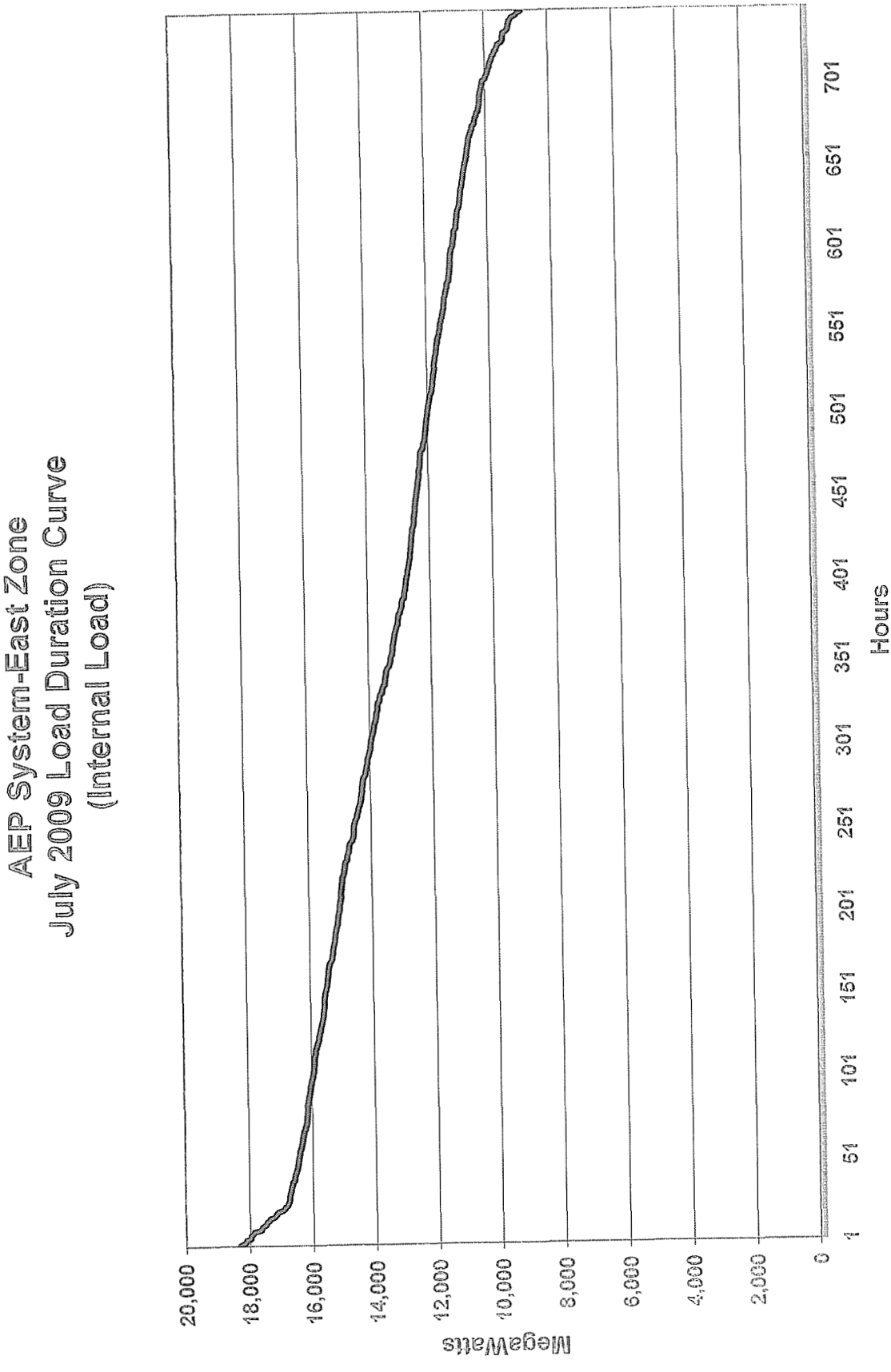

AEP System-East Zone
June 2009 Load Duration Curve
(Internal Load)
MegaWatts
20,000
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
1
51
101
151
201
251
301
351
401
451
501
551
601
651
701
Hours


AEP System-East Zone
July 2009 Load Duration Curve
(Internal Load)
MegaWatts
20,000
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
1
51
101
151
201
251
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451
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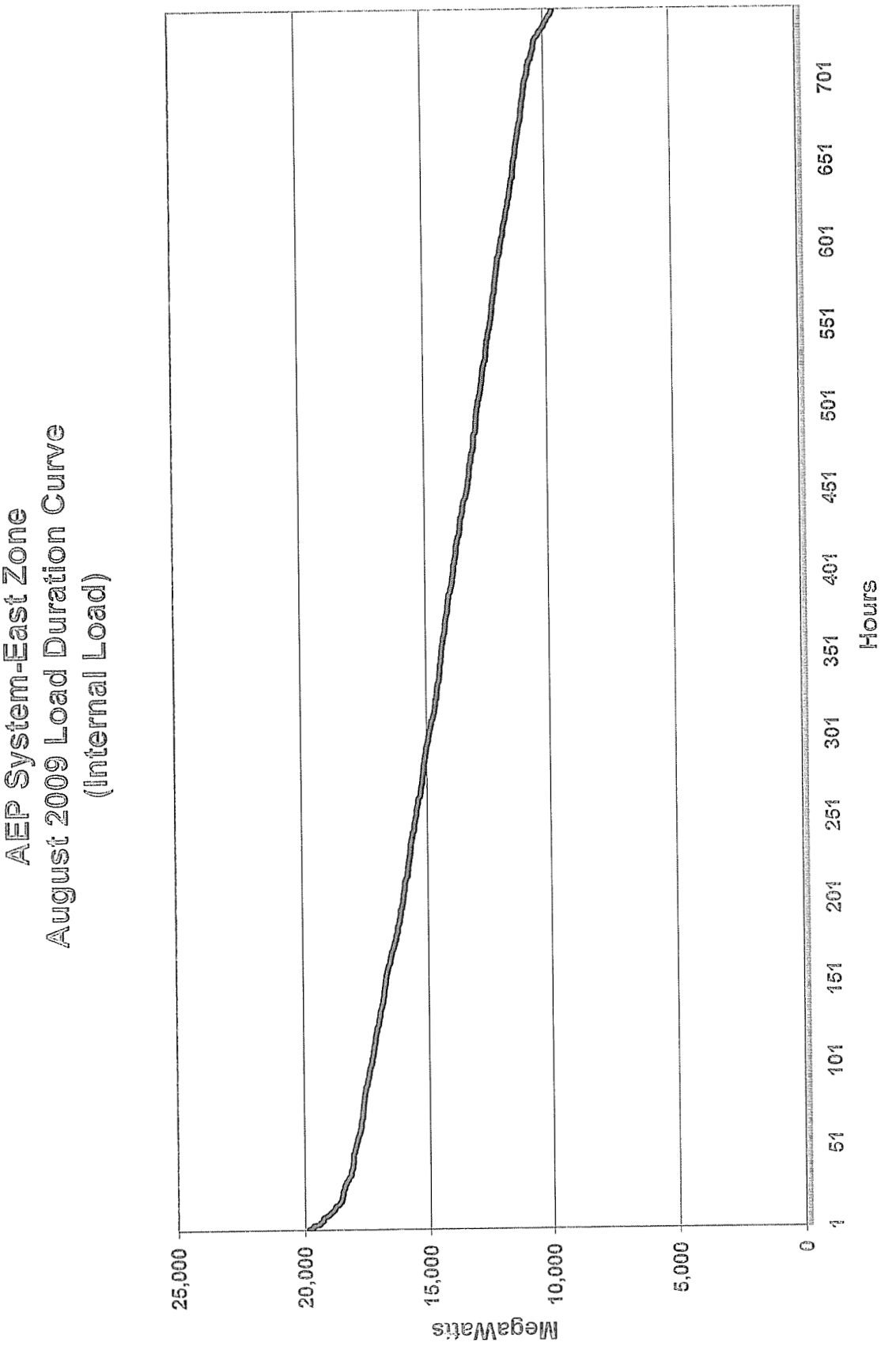
551
601
651
701
Hours


AEP System-East Zone
August 2009 Load Duration Curve
(Internal Load)
MegaWatts
25,000
20,000
15,000
10,000
5,000
0
Hours
1
51
101
151
201
251
301
351
401
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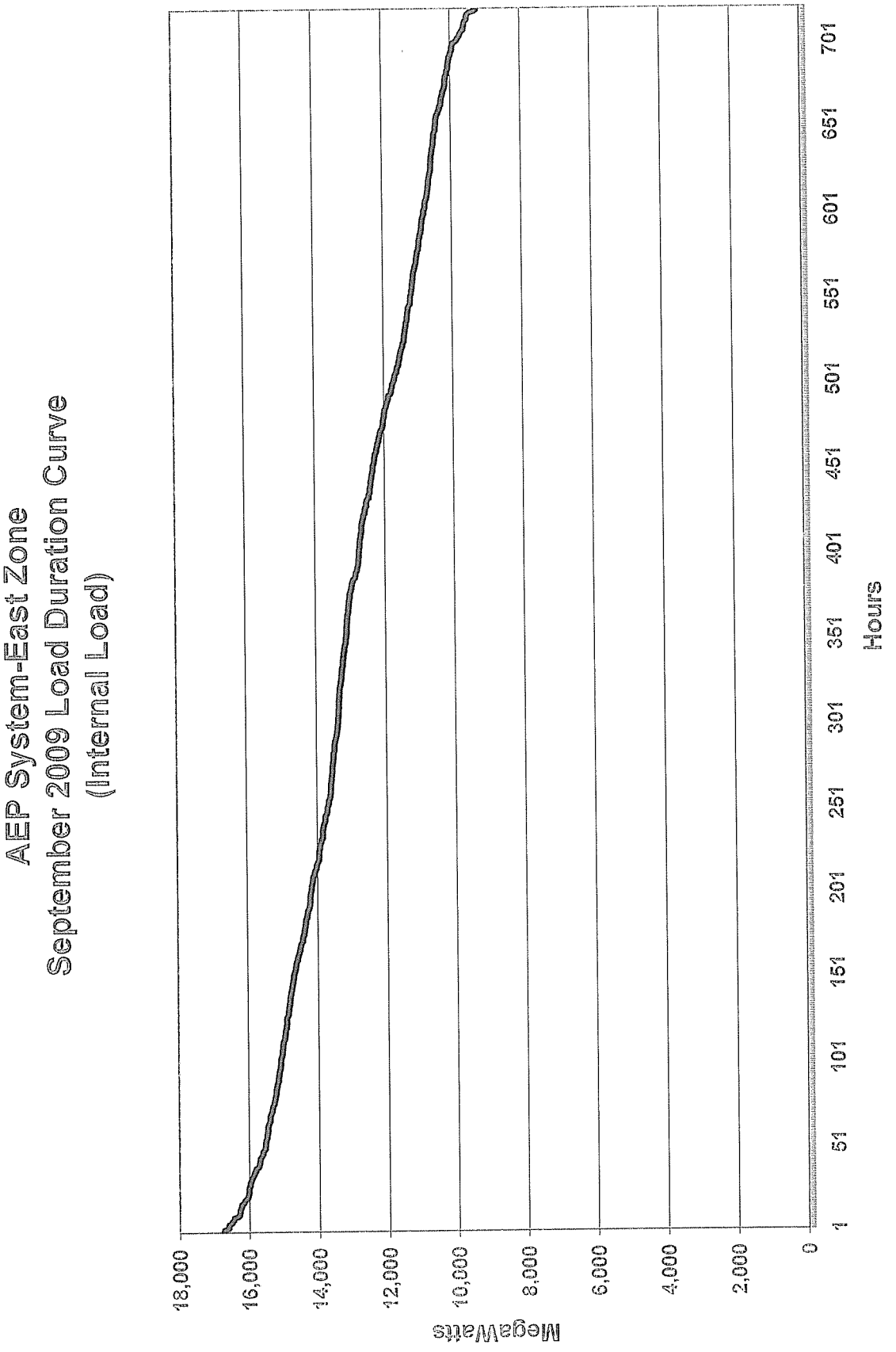
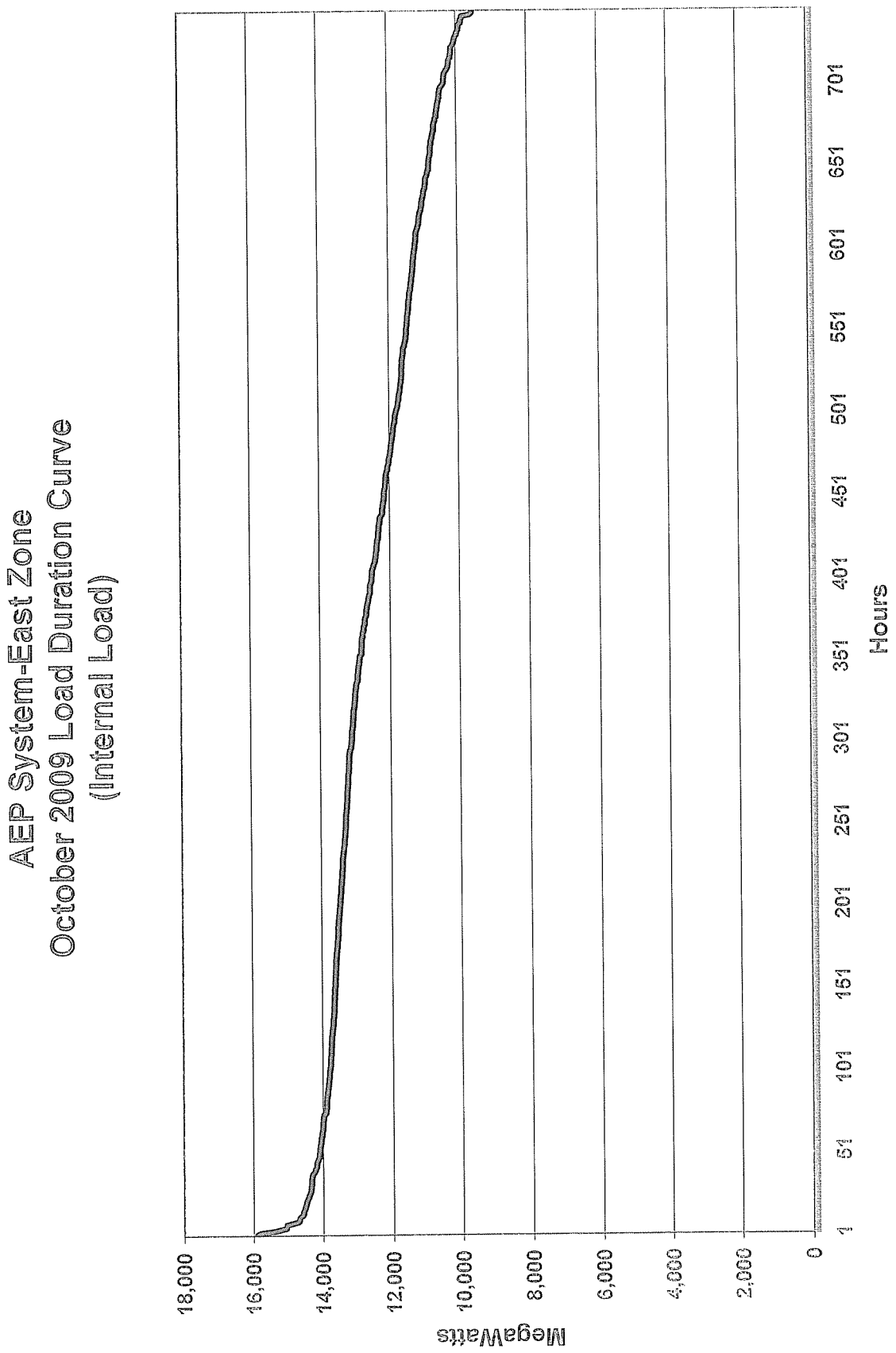
701


AEP System-East Zone
September 2009 Load Duration Curve
(Internal Load)
MegaWatts
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
1
51
101
151
201
251
301
351
401
451
501
551
601
651
701
Hours


AEP System-East Zone
October 2009 Load Duration Curve
(Internal Load)
MegaWatts
18,000
16,000
14,000
12,000
10,000
8,000
6,000
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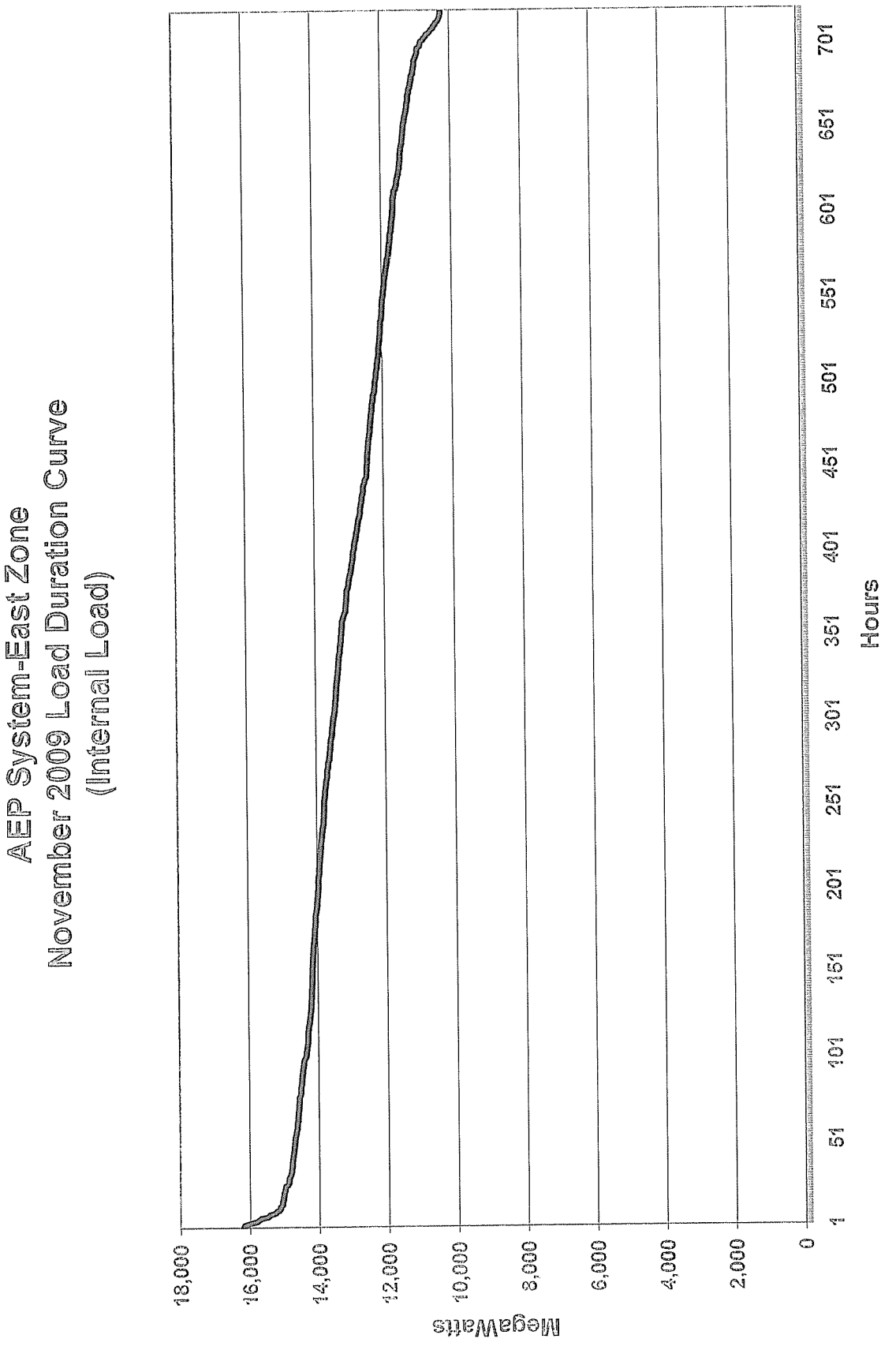
Hours


AEP System-East Zone
November 2009 Load Duration Curve
(Internal Load)
MegaWatts
18,000
16,000
14,000
12,000
10,000
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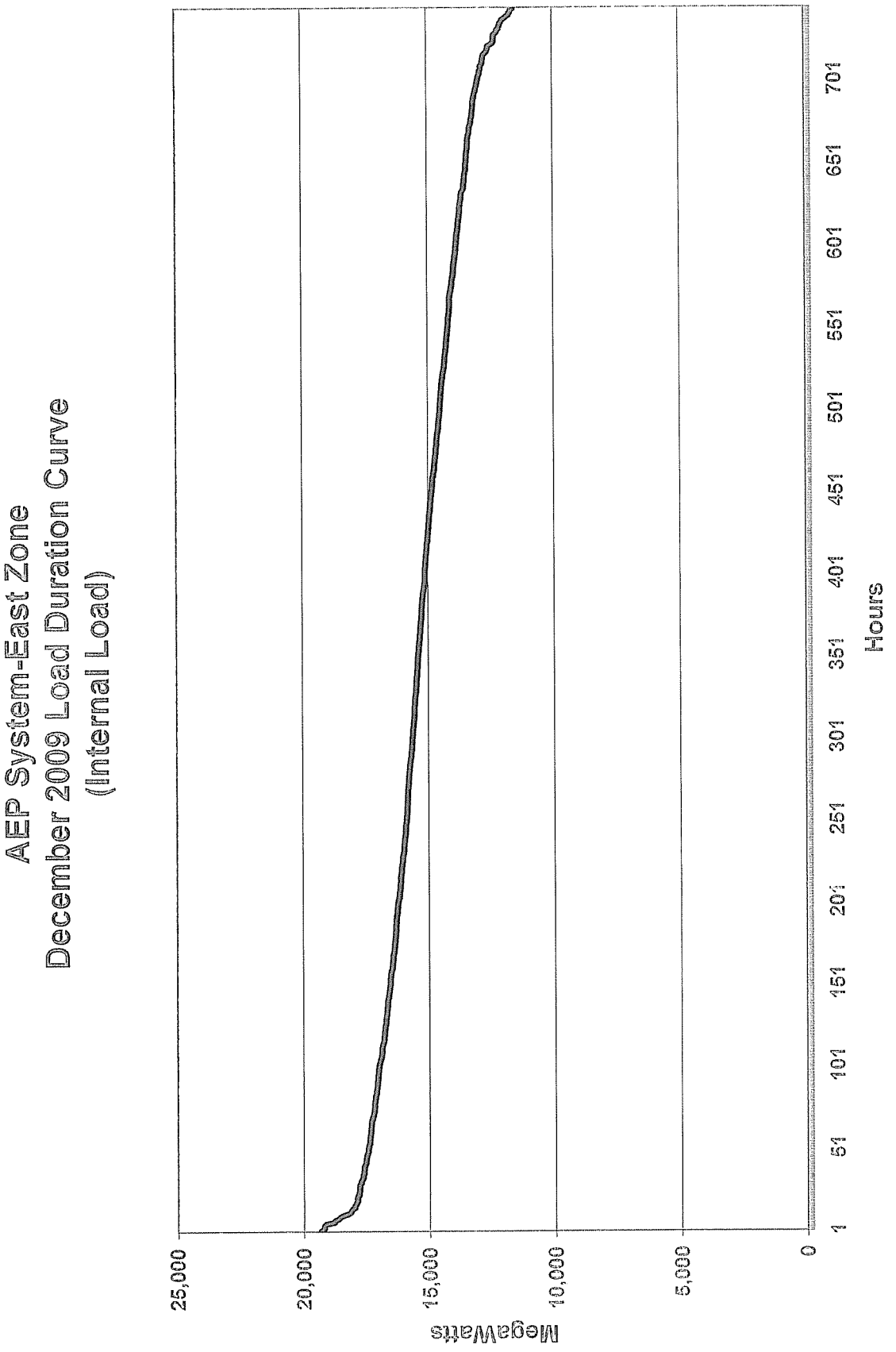
Hours


AEP System-East Zone
December 2009 Load Duration Curve
(Internal Load)
MegaWatts
25,000
20,000
15,000
10,000
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Hours
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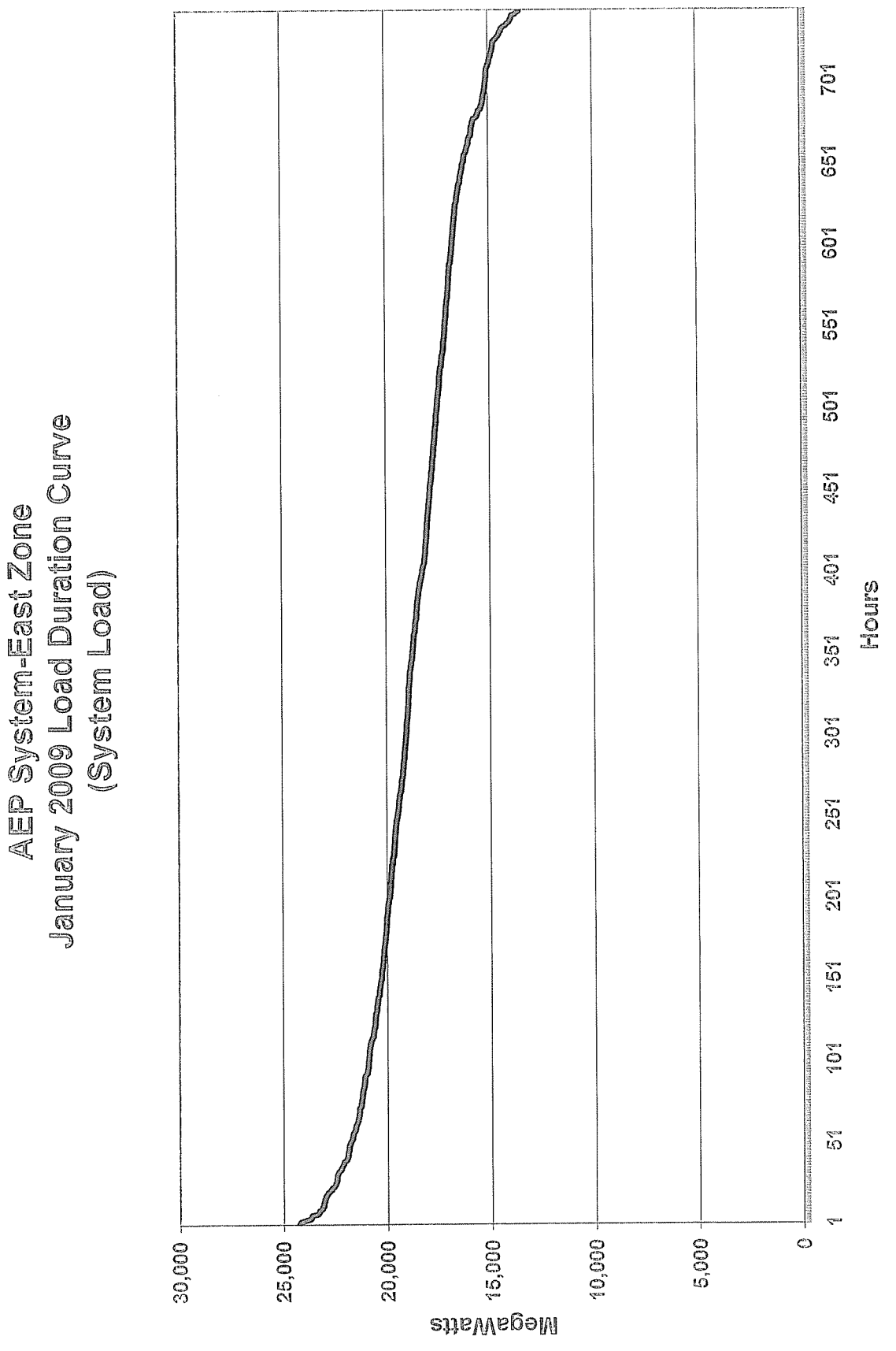
AEP System-East Zone
January 2009 Load Duration Curve
(System Load)
MegaWatts
30,000
25,000
20,000
15,000
10,000
5,000
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Hours
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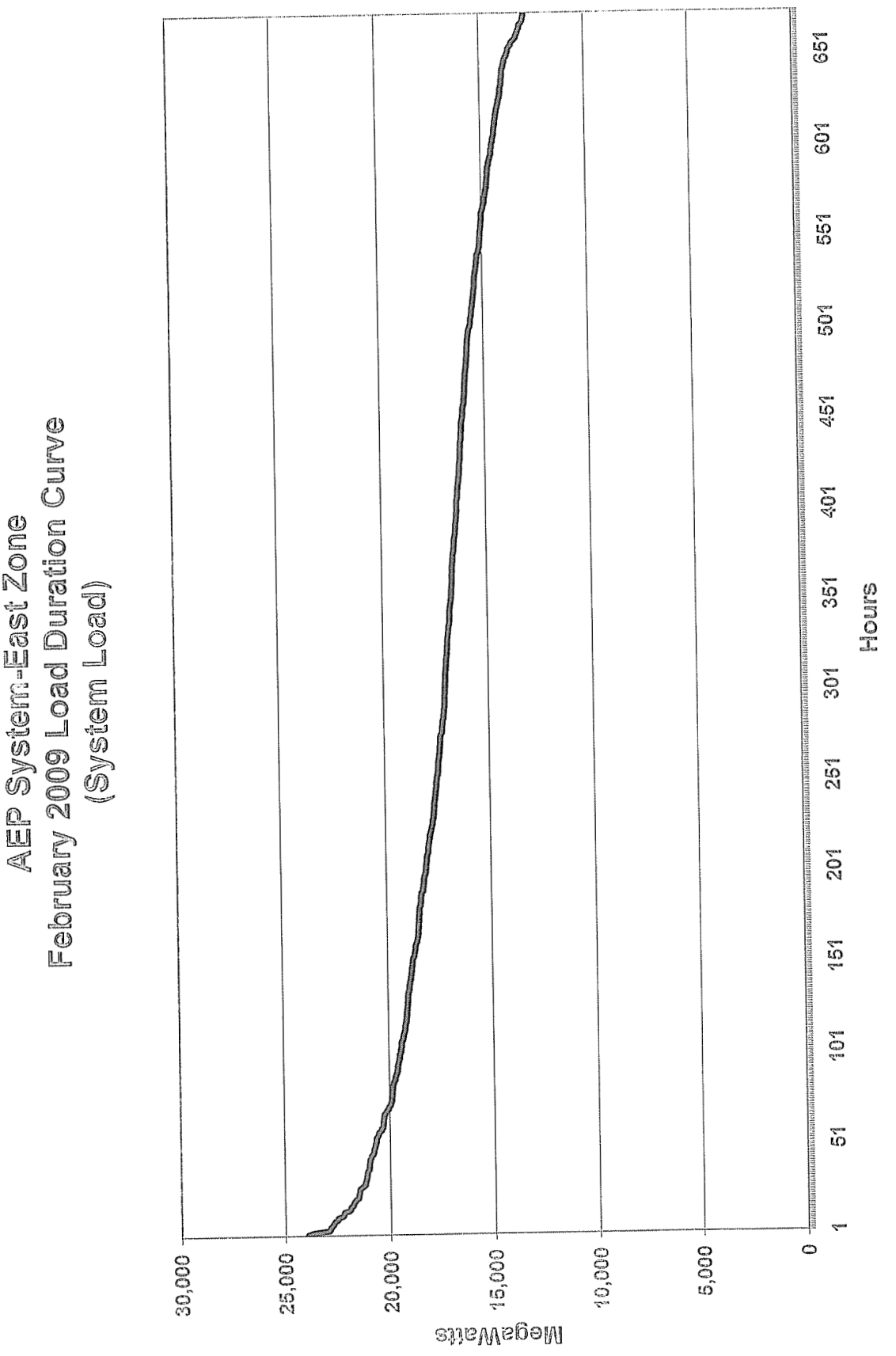
AEP System-East Zone
February 2009 Load Duration Curve
(System Load)
MegaWatts
30,000
25,000
20,000
15,000
10,000
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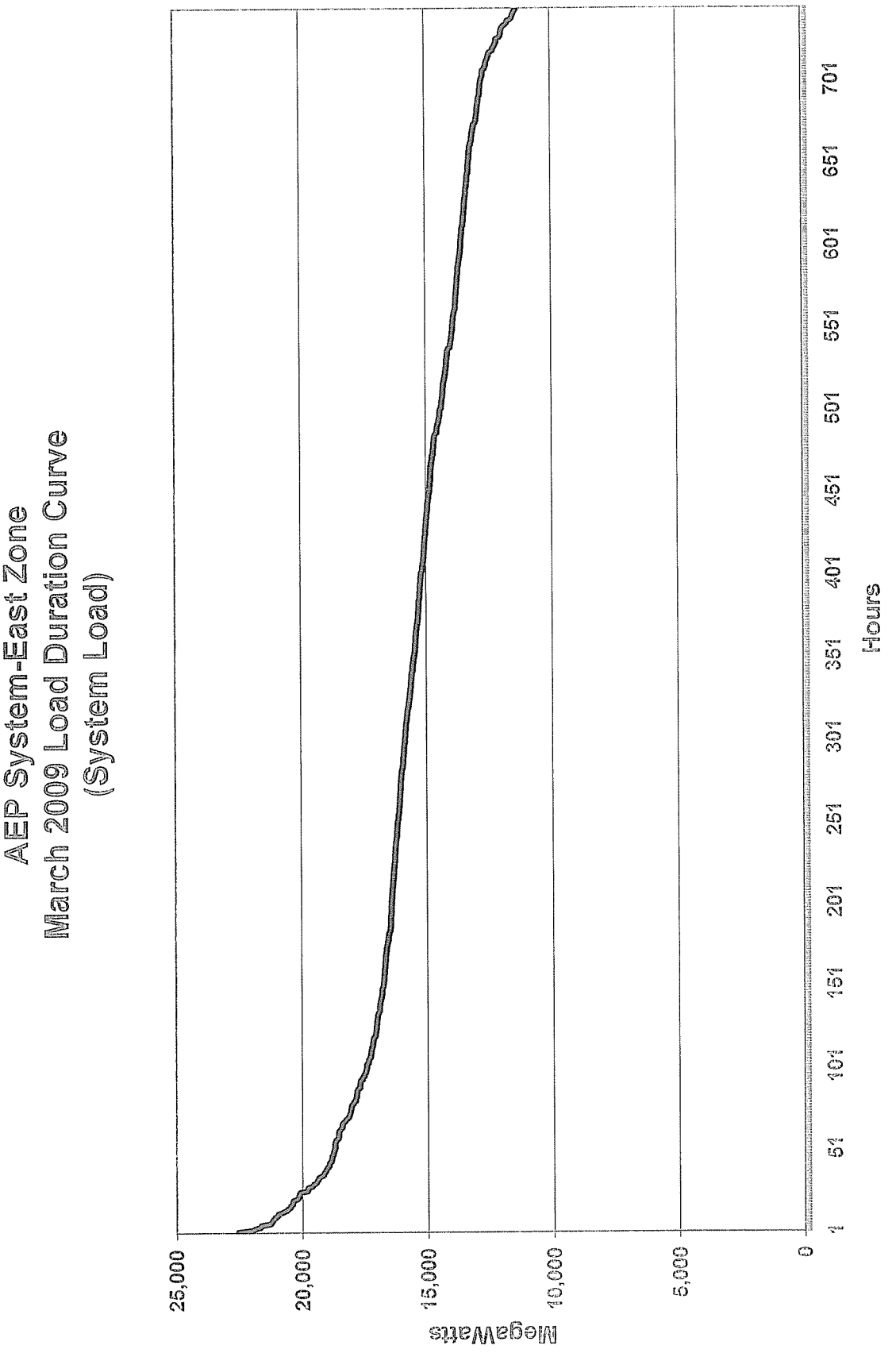
Hours


AEP System-East Zone
March 2009 Load Duration Curve
(System Load)
MegaWatts
25,000
20,000
15,000
10,000
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Hours
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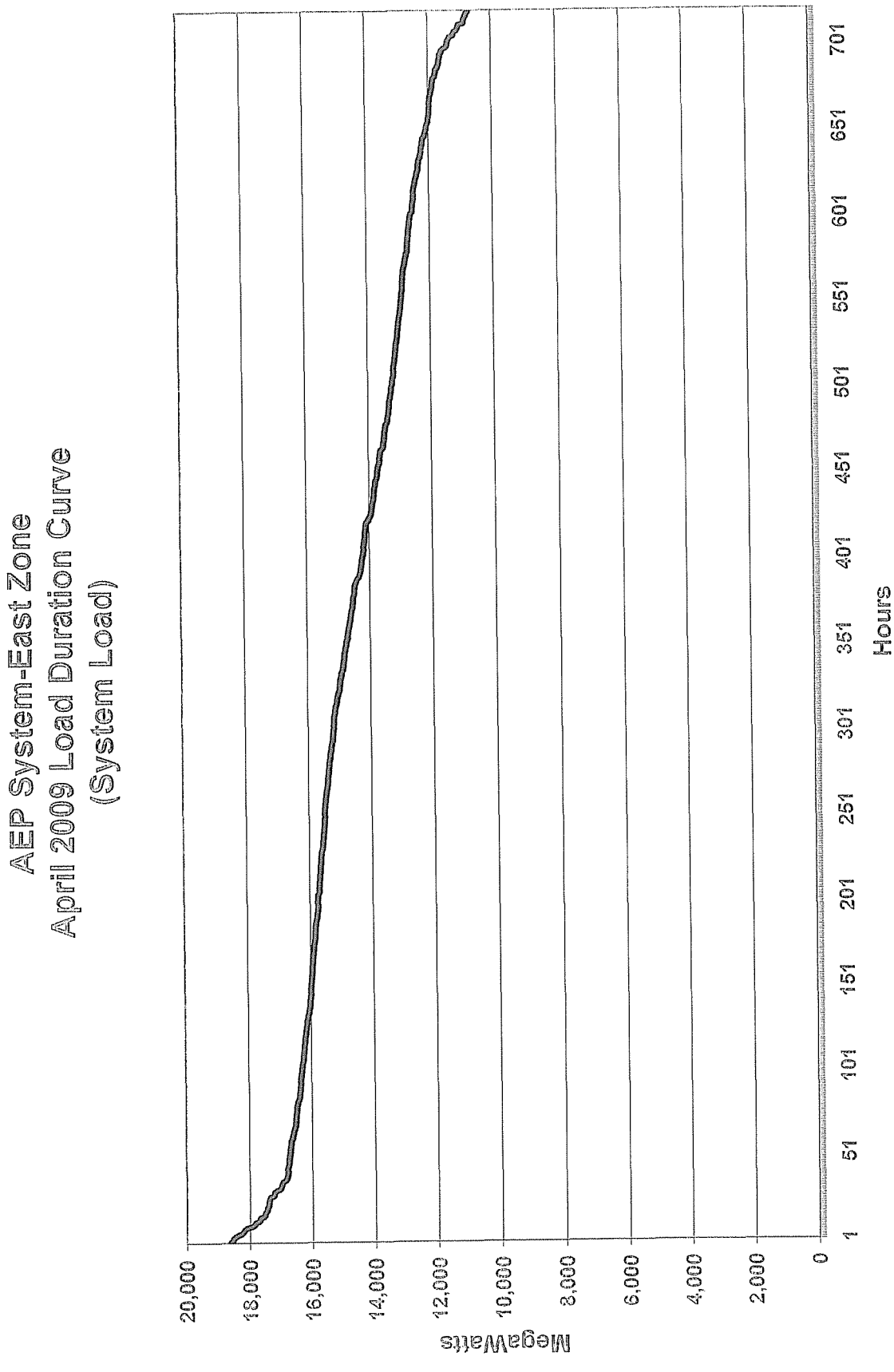
AEP System-East Zone
April 2009 Load Duration Curve
(System Load)
MegaWatts
20,000
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
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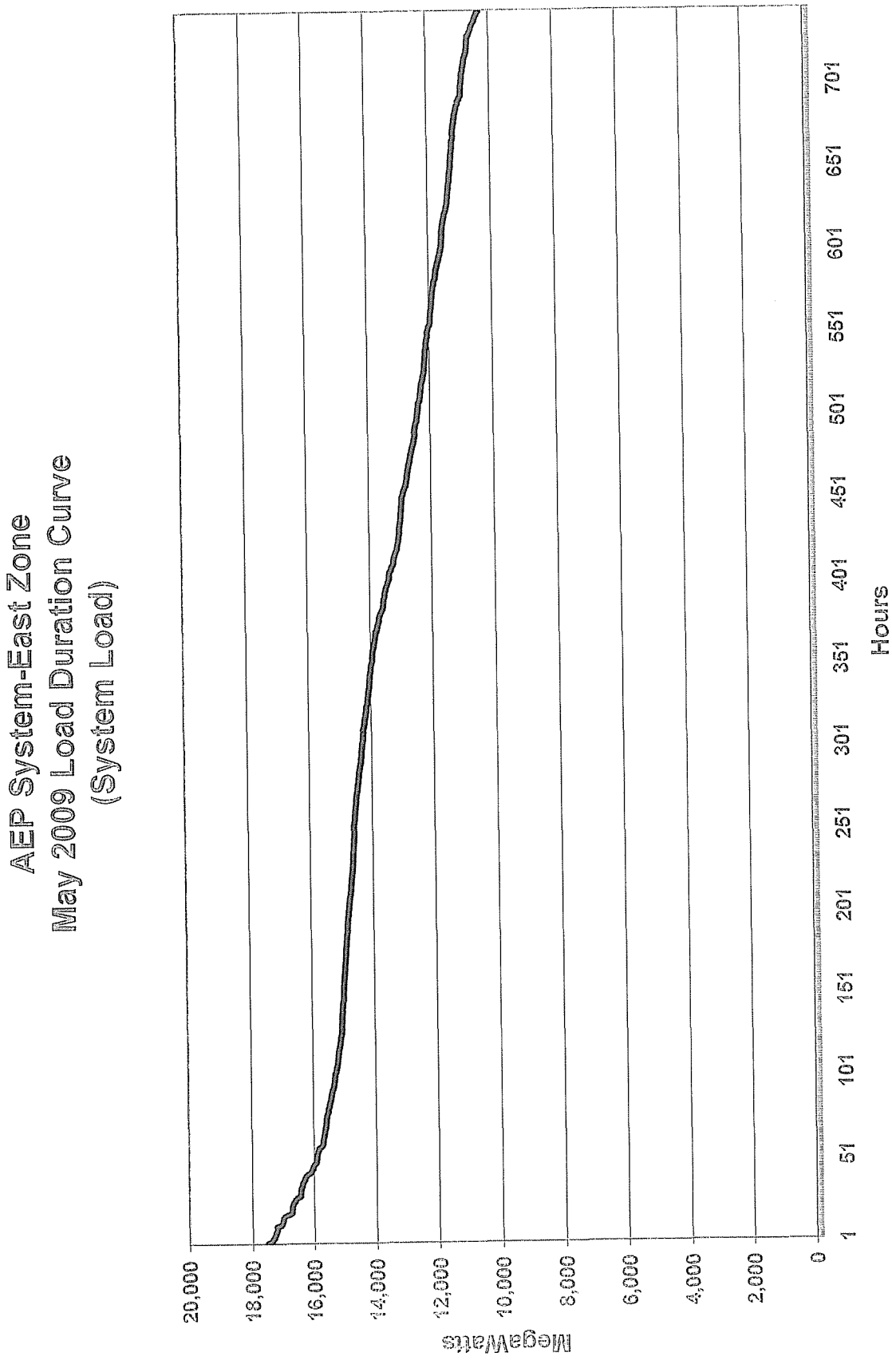
AEP System-East Zone
May 2009 Load Duration Curve
(System Load)
MegaWatts
20,000
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
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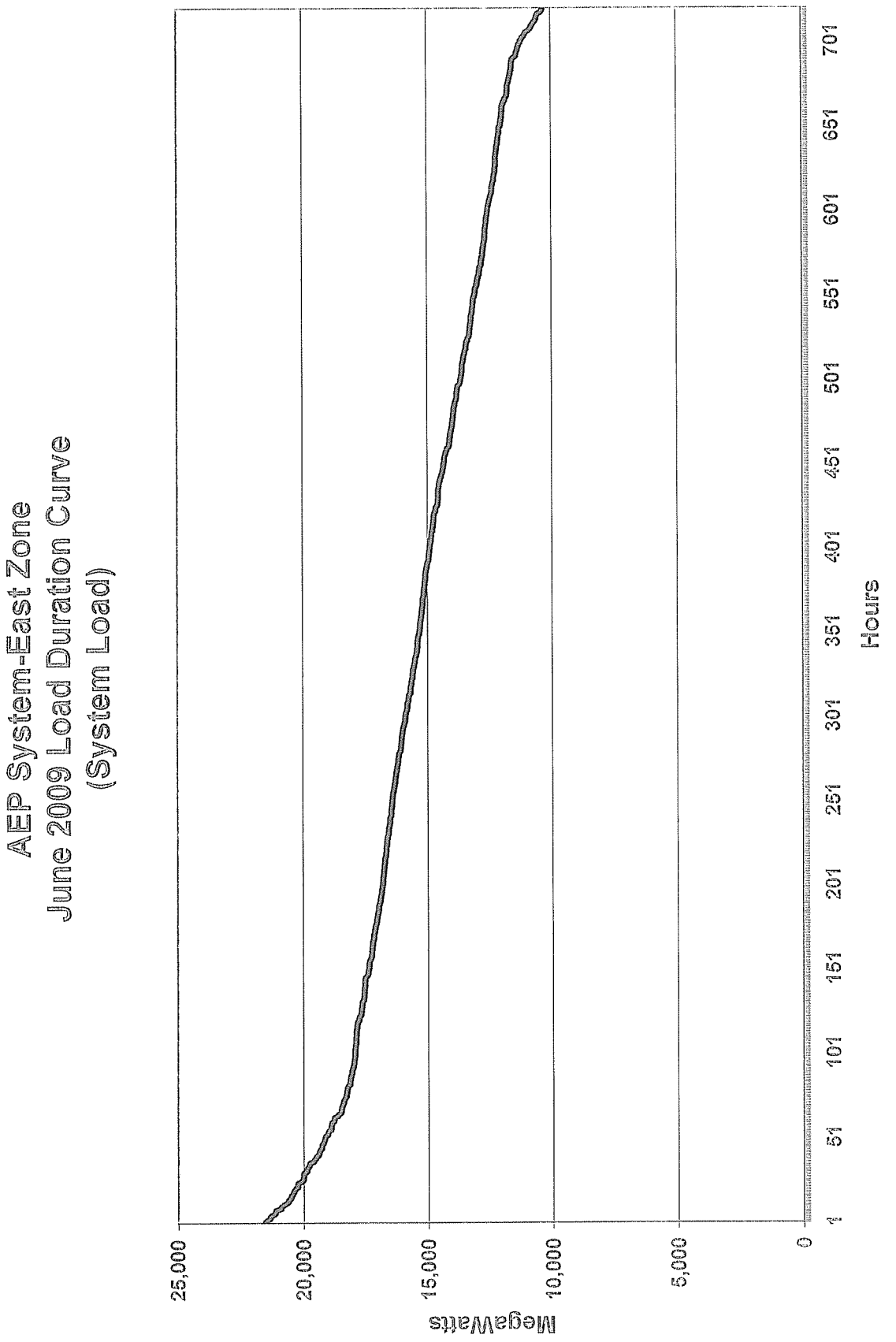
Hours


AEP System-East Zone
June 2009 Load Duration Curve
(System Load)
MegaWatts
25,000
20,000
15,000
10,000
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Hours
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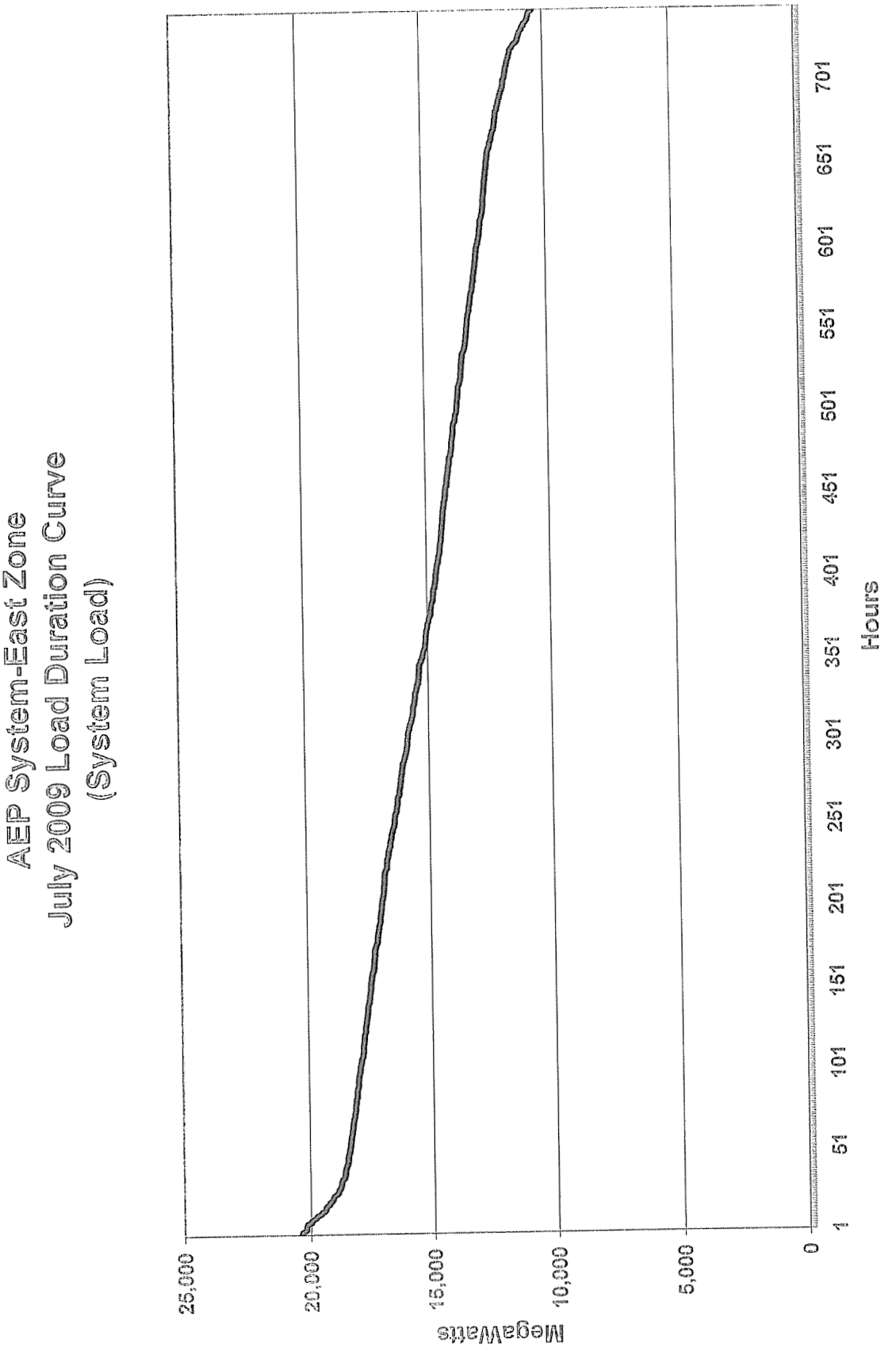
AEP System-East Zone
July 2009 Load Duration Curve
(System Load)
MegaWatts
25,000
20,000
15,000
10,000
5,000
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Hours
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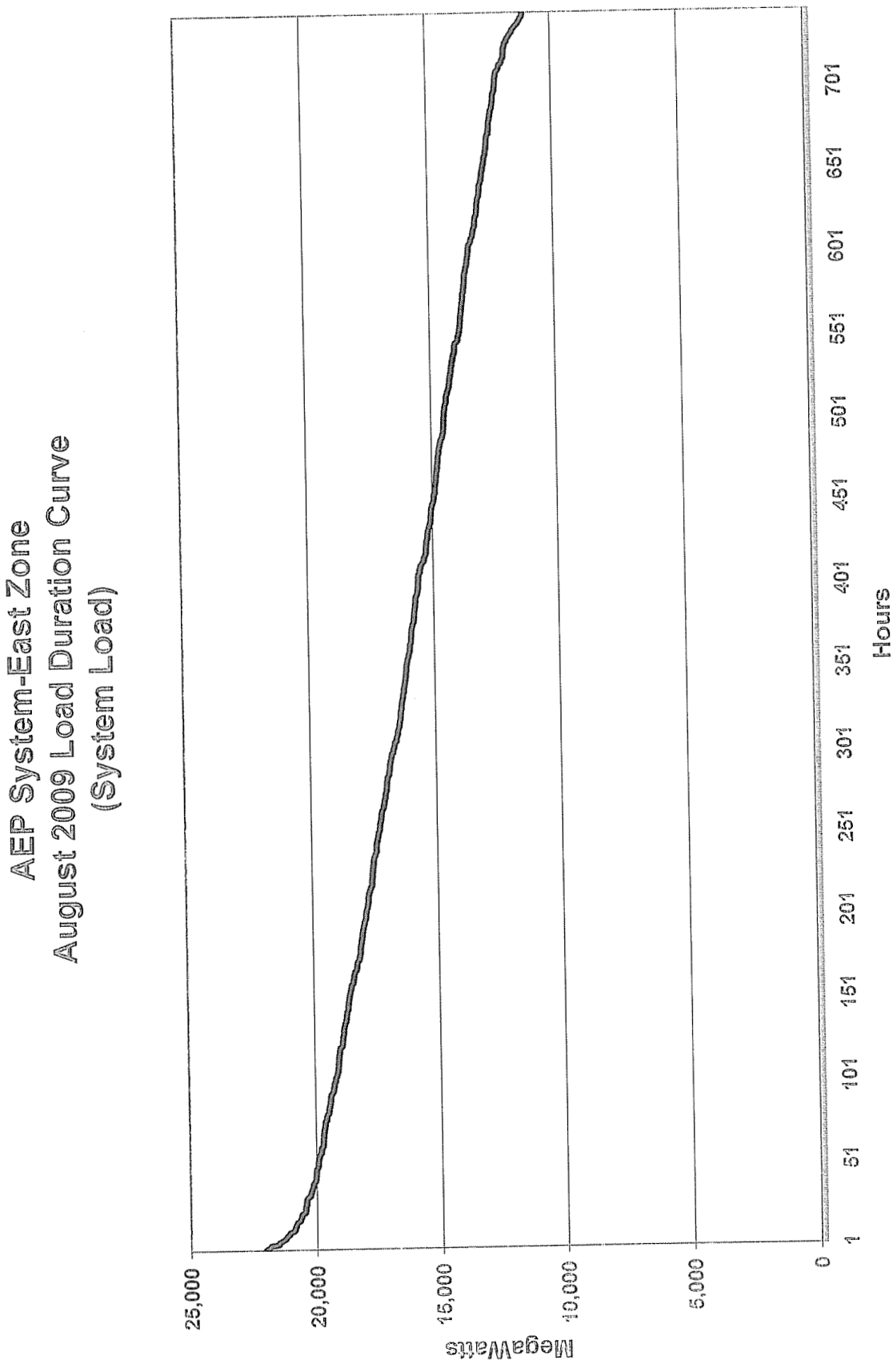
AEP System-East Zone
August 2009 Load Duration Curve
(System Load)
MegaWatts
25,000
20,000
15,000
10,000
5,000
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Hours
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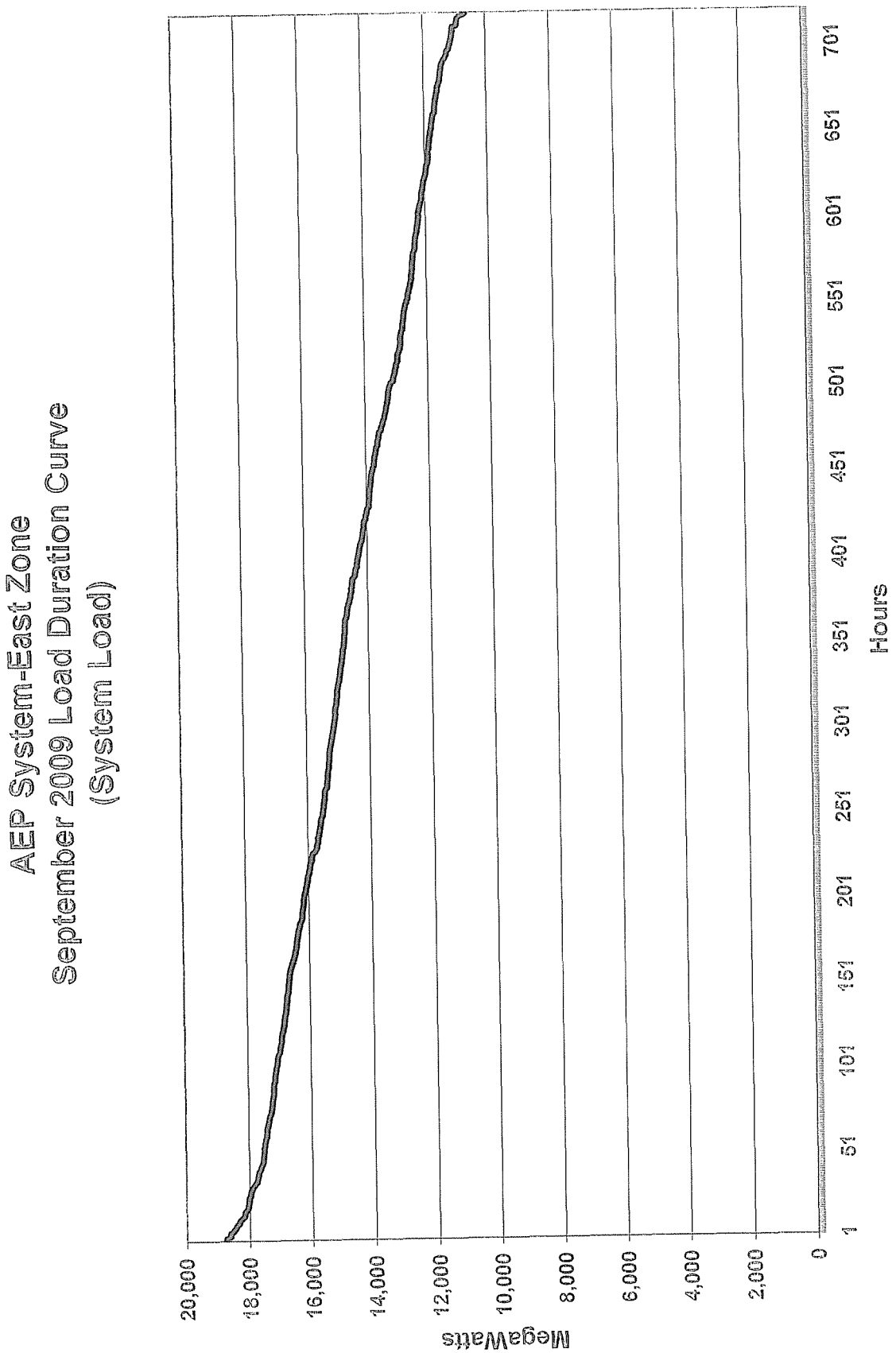
AEP System-East Zone
September 2009 Load Duration Curve
(System Load)
MegaWatts
20,000
18,000
16,000
14,000
12,000
10,000
8,000
6,000
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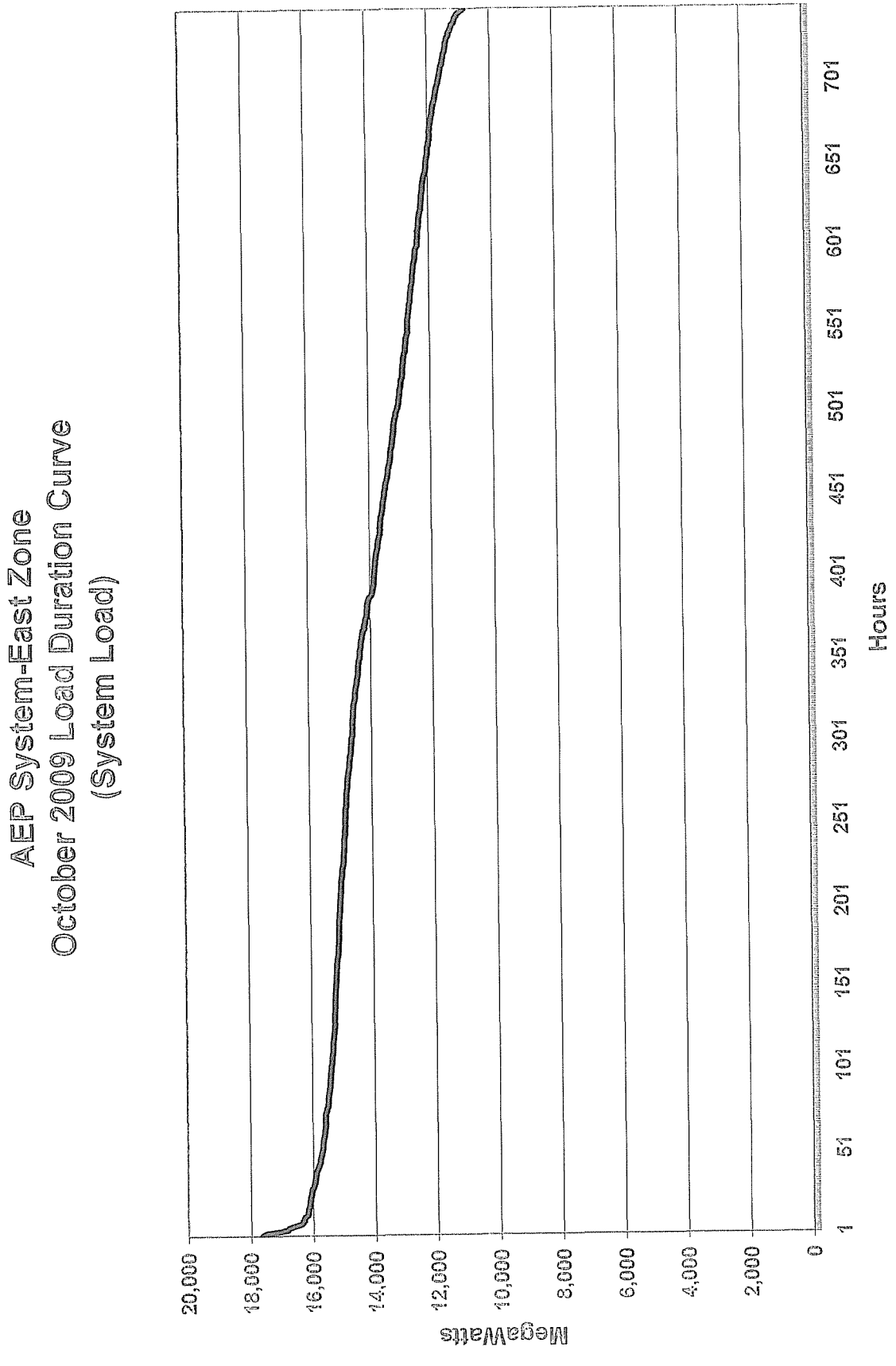
701
Hours


AEP System-East Zone
October 2009 Load Duration Curve
(System Load)
Megawatts
20,000
18,000
16,000
14,000
12,000
10,000
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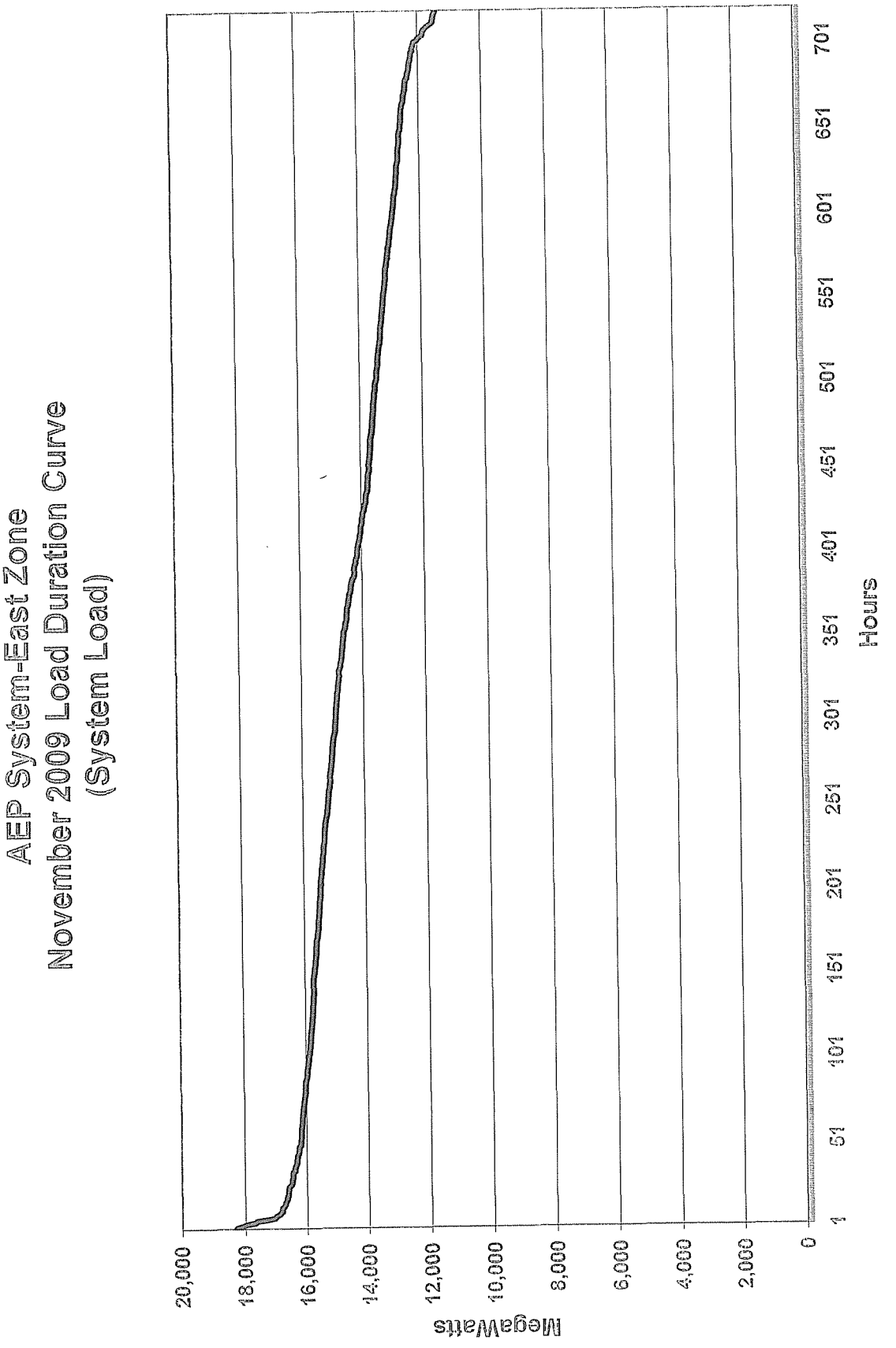
AEP System-East Zone
November 2009 Load Duration Curve
(System Load)
MegaWatts
20,000
18,000
16,000
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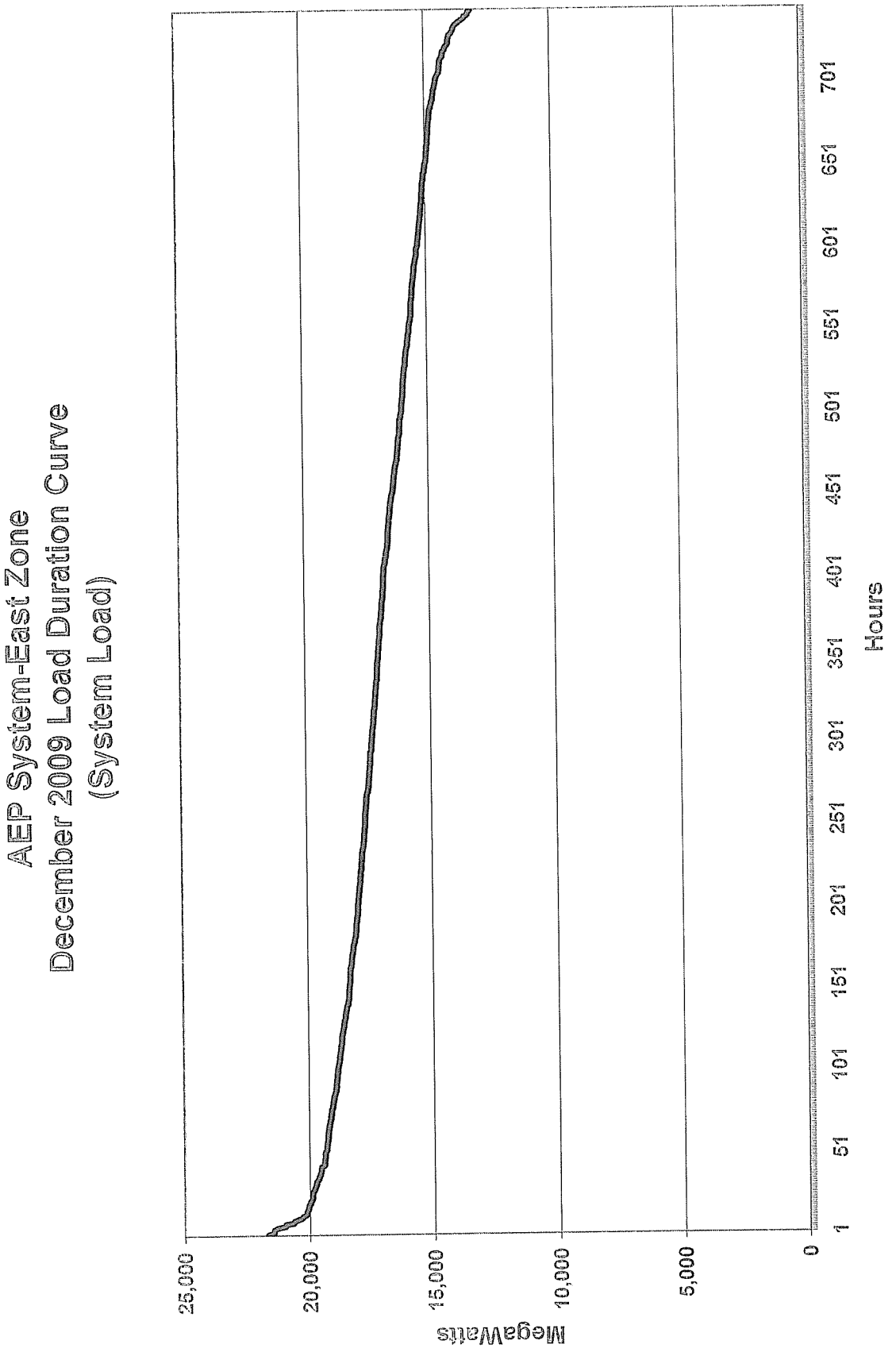
AEP System-East Zone
December 2009 Load Duration Curve
(System Load)
MegaWatts
25,000
20,000
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Kentucky Power Company

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 2 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.

Page 3 provides AEP System-East'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 off-system energy sales forecasts for Kentucky Power Company and AEP System-East are provided on Page 4 of this response. Forecasts of off-system peak demand for Kentucky Power Company and AEP System-East 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.

WITNESS: Errol K Wagner

Kentucky Power Company
Base and High Forecast
Energy Sales (GWH) and Seasonal Peak Demand (MW)
2009 - 2013

Year	Energy Sales		Summer Peak Demand		Preceding Winter Peak Demand	
	Base	High	Base	High	Base	High
2009	8,144	8,480	1,338	1,393	1,639	1,707
2010	8,286	8,699	1,357	1,424	1,668	1,751
2011	8,354	8,827	1,364	1,441	1,672	1,767
2012	8,417	8,979	1,379	1,471	1,689	1,802
2013	8,472	9,136	1,389	1,498	1,700	1,834

AEP System-East Zone
Base and High Forecast
Energy Sales (GWH) and Seasonal Peak Demand (MW)
2010 - 2014

Year	Energy Sales		Summer Peak Demand		Preceding Winter Peak Demand	
	Base	High	Base	High	Base	High
2010	124,680	129,828	21,453	22,339	20,631	21,482
2011	127,247	133,585	21,813	22,899	21,178	22,233
2012	128,748	136,040	22,041	23,289	21,316	22,523
2013	129,874	138,546	22,321	23,811	21,582	23,023
2014	130,808	141,062	22,524	24,289	21,749	23,454

Kentucky Power Company and AEP-System-East
Forecast Off-System Energy Sales (GWh)
2010 - 2014

Year	KPCo Off-System Sales	AEP-East Off-System Sales
2010	1,530	21,433
2011	1,769	24,914
2012	2,027	28,861
2013	1,790	25,778
2014	1,874	27,081

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 is recalculated each year, depending on five-year average generation reliability, PJM load shape, and assistance available from neighboring regions. In addition, AEP'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. Exhibit 4 attached to this response provides an example of the PJM reserve requirement calculation.

For the 2010/11 and 2011/12 delivery periods PJM has set the IRM at 15.5%. For the 2012/13 delivery period PJM initially set the IRM at 16.2% and for planning purposes AEP assumed a 16.2% level for future years. (Late in 2009 PJM reduced the 2012/13 IRM to 15.4% and set the 2013/14 IRM at 15.3%.) The resulting AEP reserve requirement ranges from 15.7% to 25.4%, as shown in Exhibit 5-2 attached to the response to Question 5. (This compares with 12% that AEP used, based on our own determinations, from the late 1990s until 2004, and 15% prior to that.) Note that the reserve requirement appears higher for 2010. This is due to the fact that the actual AEP EFORd rate of 11.18% used to calculate this year's requirement is considerably higher than the EFORds which are used to calculate the requirement in the other years.

Currently, Kentucky Power Company is capacity deficient on a stand-alone basis. The basis of the AEP Interconnection Agreement is that, over time, each member, including Kentucky Power Company, is responsible for installing its share of the System capacity. However, other members of the AEP Interconnection Agreement are more deficient at this time and it is the members with the highest capacity deficiencies that are expected to add capacity first.

WITNESS: Errol K Wagner

KPSC Adm. Case No. 387
Order Dated December 13, 2004
Exhibit 4

PJM Reserve Margin Example For 2010/11 Planning Year

Line				Comment
1	Factors			
2	PJM Installed Reserve Margin (IRM)	=	15 50%	
3	PJM EFORd	=	6 21%	Based on 5-year average PJM EFORd
4	Forecast Pool Requirement (FPR)	=	1.0833	FPR = (1 + Line 2) * (1 - Line 3)
5				
6	Obligations			
7	Total Load Obligation	=	21,487	Coincident peak forecasted by PJM
8	UCAP Obligation	=	23,277	Line 4 * Line 7
9	UCAP Market Obligations	=	1,400	
10	Total UCAP Obligation	=	24,677	Line 8 + Line 9
11				
12	Resources			
13	Net ICAP	=	27,248	
14	AEP EFORd	=	11.18%	MW-weighted average of Unit EFORds
15	Available UCAP	=	24,202	Line 13 * (1- Line 14)
16				
17	Position			
18	Net UCAP Position	=	(475)	Line 15 - Line 10
19	Net ICAP Position	=	(535)	Line 18 / (1- Line 14)
20				
21	Reserve Margin Percent	=	22 9	Question 5 attached Exhibit 5-2, Column (16)
22	Reserve Percent Required By PJM	=	25 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

The attached Exhibit 5-1 to this response provides projected winter peak demands, capabilities, and margins for KPCo for the winter seasons 2009/10 through 2013/14.

The attached Exhibit 5-2 to this response provides projected summer peak demands, capabilities, and margins for the AEP System - East Zone for the period 2010 through 2014.

WITNESS: Errol K Wagner

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

	Peak Demand - MW						Capacity - MW						Margin	
							Existing	Sales	Capacity Additions		Purchases			
Winter Season	Internal Demand (a)	DSM and Solar (b)	Committed Sales (c)	Total Demand	Inter-ruptible Demand	Total Demand	Capacity & Chngs (d)	Net Sales (e)	Name/ Identifier	MW (f)	Annual Mkt. Purch.	Total Equivalent Capacity	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
2009/10	1,640	(8)	15	1,647	0	1,647	1,453	72	No New Build	0	0	1,381	(266)	(16.2)
2010/11	1,670	(16)	0	1,654	0	1,654	1,453	72	50 MW Wind	6	0	1,387	(267)	(16.1)
2011/12	1,674	(18)	0	1,656	0	1,656	1,453	66	50 MW Wind	6	0	1,400	(256)	(15.5)
2012/13	1,691	(20)	0	1,671	0	1,671	1,453	(8)	No New Build	0	0	1,474	(197)	(11.8)
2013/14	1,702	(22)	0	1,680	0	1,680	1,453	(9)	No New Build	0	0	1,475	(205)	(12.2)

Notes: (a) Based on May 2009 Load Forecast.

(b) Existing plus approved DSM plus projected solar resource impact.

(c) Includes companies MLR share of:
NCEMC sale, through 2010 (220 MW)

(d) Reflects winter capability assumptions.

(e) Includes companies MLR share of:
Purchase from Constellation (315 MW), 2009/10 through 2011/12
Contractual share of remaining Mone capacity
Sale of 22 MW from Tanners Ck. 4 in 2010/11-2013/14
RPM Auction Sales 2009/10-2011/12 (1397 MW, 1404 MW, 1391 MW ICAP)
3.6 MW capacity credit from SEPA's Philpot Dam via Blue Ridge contract

(f) New wind capacity value is assumed to be 13% of nameplate

AEP SYSTEM - EAST ZONE
Projected Summer Peak Demands, Generating Capabilities, and Margins

Summer Season	Peak Demand - MW						Capacity - MW						Reserve Margin		Reserve Margin		PJM ICAP Position After Interruptible w/ New Capacity	
	Internal Demand (a)	Inter-ruptible Demand (b)	DSM and Solar (c)	Net AEP Internal Demand	Net Other Committed Sales (d)	Total AEP Demand	Existing Capacity & Planned Changes (e)	Committed Net Sales (f)	Planned Capacity Additions Name/ Identifier	MW (g)	Annual Purch.	Total Capacity	Before Interruptible w/ New Capacity MW	% of Demand	After Interruptible w/ New Capacity MW	% of Demand	Reserve % Required By PJM	Net Position MW
	(1)	(2)	(3)	(4)=Sum(1 thru 3)	(5)	(5)=(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		
2010	21,308	(615)	(326)	20,367	1,274	21,641	27,640	1,123	350 MW Wind	46	0	26,589	4,333	19.5	4,948	22.9	25.4	(535)
2011	22,640	(615)	(629)	21,396	1,052	22,448	27,648	1,052	600 MW Wind	78	0	26,746	3,683	16.0	4,298	19.1	15.7	763
2012	22,869	(615)	(816)	21,438	1,043	22,481	27,091	(33)	60 MW Bio Mass & 700 MW Wind	151	0	27,425	4,329	18.7	4,944	22.0	15.9	1,372
2013	23,149	(615)	(1,007)	21,527	1,043	22,570	27,081	(35)	540 MW D CC & 500 MW Wind.	605	0	28,022	4,837	20.9	5,452	24.2	16.1	1,817
2014	23,354	(615)	(1,196)	21,543	1,043	22,586	26,701	(33)		0	0	27,640	4,439	19.1	5,054	22.4	18.7	844

Notes:

(a) Based on May 2009 Load Forecast (not coincident with PJM's peak).

(b) Load forecasting view of Interruptible Demand.

(c) Existing plus approved DSM plus projected solar resource impact.

(d) Includes:
Buckeye-Cardinal commitment
NCEMC sale, through 2010 (220 MW)

(e) Reflects the following summer capability assumptions:
AEP PPR share of OVEC capacity: 951 MW (Summer)
Hydro plants, including Summersville, are rated at average August output.
CCS DERATES.
2010: Mountaineer: 5 MW
2014: Mountaineer: 30 MW
FGD DERATES.
2010: Kyger Creek 3-5: 3 MW each
2011: Kyger Creek 1-2: 3 MW each
2012: Amos 2: 22 MW; Cardinal 3: 10 MW; Clifty Creek 1-6: 2 MW each;
2013 Amos 1: 22 MW
EFFICIENCY IMPROVEMENTS.
2011: 14 MW
2012: 12 MW
2013: 12 MW
2014: 45 MW

(e) continued
ASSUMED RETIREMENTS FOR PLANNING PURPOSES:
2010: 440 MW
2012: 560 MW
2014: 395 MW

(f) Includes:
Purchase from Constellation (315 MW), 2009 through 2011
Contractual share of remaining Mone capacity
Sale of 22 MW from Tanners Ck. 4 in 2010-2014
RPM Auction Sales 2010-2011 (1404 MW, 1391 MW ICAP)
3.6 MW capacity credit from SEPA's Philpot Dam via Blue Ridge contract

(g) New wind capacity value is assumed to be 13% of nameplate.

Resource Planning
Created: 3/26/2009 11:41:16 AM
Modified: 3/26/2009 11:41:16 AM

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

Listed below are the outages scheduled for Big Sandy units as of this date.

YEAR	UNIT 1	UNIT 2
2010	More than 4 weeks	Less than 4 weeks
2011	Less than 4 weeks	More than 4 weeks
2012	Less than 4 weeks	Less than 4 weeks
2013	Less than 4 weeks	More than 4 weeks
2014	More than 4 weeks	Less than 4 weeks

There are no plans to retire generating capacity during the current year or following four years.

WITNESS: Errol K. Wagner

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

At the present time, AEP is evaluating a mix of generation resources to meet its projected capacity needs through 2020. Although the precise timing, mix of technology, location and size of such additions remain under review, for planning and projection purposes, System expansion plan includes these additions:

Date	Size, MW	Type	Site
2010	100	wind purchase	West Virginia
2010	250	wind purchase	unknown
2011	600	wind purchase	unknown
2012	700	wind purchase	unknown
2012	60	Biomass	unknown
2013	540	combined cycle	Dresden, O.
2013	500	wind purchase	unknown
2016	100	wind purchase	unknown
2018	127	Biomass	unknown
2018	4 x 157	combustion turbines	unknown
2020	200	wind purchase	unknown

WITNESS: Errol K Wagner

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

a.&b. Please see attached Page 2 of this response.

WITNESS: Errol K Wagner

8(a) All quantities represent metered values.

Received from (MWh):	2004 (Actual)	2005 (Actual)	2006 (Actual)	2007 (Actual)	2008 (Actual)	2009 (Actual)	2010
Appalachian Power (1)	11,066,166	11,871,456	9,485,862	7,280,995	7,826,055	4,637,687	(4)
Ohio Power (1)	9,766,209	8,687,031	9,470,141	7,782,679	8,832,135	10,872,502	(4)
East Ky Power Coop	279,973	362,963	398,269	324,865	402,847	481,140	(4)
LGE(Kentucky Utilities)	95,146	137,523	330,912	600,592	810,871	933,540	(4)
TVA	700,836	649,374	501,071	390,216	448,365	523,823	(4)
Illinois Power Co (2)	0	34,647	13,555	38,216	33,190	35,408	(5)
Illinois Power Co (3)	752	30,508	11,908	24,485	23,629	16,769	(5)
Big Sandy Generating Plant	6,550,509	7,345,624	7,171,505	7,533,223	6,021,182	6,262,165	6,386,000

8(b) All quantities represent metered values.

Delivered to (MWh) :	2004	2005	2006	2007	2008	2009	
Appalachian Power (1)	20,152,403	20,485,009	18,982,168	15,501,979	15,917,326	15,589,080	(4)
Ohio Power (1)	205,829	303,310	215,747	257,462	360,333	465,000	(4)
East Ky Power Coop	314,621	263,853	218,005	277,818	213,189	154,558	(4)
LGE(Kentucky Utilities)	1,205	476	97	370	14	11	(4)
TVA	116	86	70	6,050	62	0	(4)
Illinois Power Co (2)	1,267	0	0	0	0	0	(5)
Illinois Power Co (3)	308	0	0	0	0	0	(5)
Vanceburg and Olive Hill			98,517	101,705	101,657	95,284	(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 2006 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 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 Question 9 will provide adequate capacity to serve the existing and projected loads shown in the table below.

d. The actual summer and winter peak demands are shown below for 2009/2010. In addition, forecasted summer and winter peak demands for 2010 through 2014 are also shown in the table below.

Kentucky Power Company
Seasonal Peak Demand
Actual 2009 and Forecast 2010-2014

Year	Summer Peak Demand (MW)	Preceding Winter Peak Demand (MW)
2009	1163*	1674*
2010	1298	1543*
2011	1316	1618
2012	1323	1623
2013	1338	1639
2014	1348	1650

*Based on Actual Load Data

WITNESS: Errol K. Wagner

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

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

Coalton Area Network Improvement - Tap the Chadwick-KES 138 kV circuit and install a new 138/69 kV 200 MVA transformer at the Coalton station. This project will alleviate thermal overload and heavy loading conditions, improve reliability, and provide margin for future growth in the South Neal-Coalton-Bellefonte area. Current projected in service date is 2012.

Thelma-Paintsville Area Project - Add a 138/69 kV, 90 MVA transformer at Thelma Station and construct 1.8 miles of 69 kV line from West Paintsville Station to Paintsville Station. Convert Thelma-Paintsville 46 kV line to 69 kV to close the 69 kV loop. This project will provide single contingency reliability to the Paintsville area. Current projected in service date is December 2012-2013.

Lee City Station Interconnection – This a joint project with East Kentucky Power Company (EKPC). Closing this normally open interconnection point with EKPC at AEP's Lee City 69 kV Station will provide interim voltage support into the Hazard, Kentucky Area and is an intermediate solution until the *Hazard Area Improvement Project* can be completed. Station and line work will be required by AEP in order to establish this tie point. Current projected in service date is December, 2010.

Morgan County Interconnection Station – This is a companion project to the Lee City Interconnection. It will establish a new interconnection station with EKPC approximately 11 miles north of AEP's Lee City Station. This new station will be able to accommodate a future distribution station expansion. Both Lee City and Morgan County Interconnections are covered under a revised Interconnection Services Agreement signed by AEP and EKPC.

Hazard Area Improvements Project – This project 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 systems. Current projected in service date is December, 2014.

WITNESS: Errol K. Wagner