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PUCO EXHIBIT FILING

Date of Hearing: 1/21/2016

Case No. 14-1297-EL-SSO

PUCO Case Caption: In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan. Volume XL

List of exhibits being filed:

Company 177, 179, 180
OMAEG 26A, 27, 29

Reporter's Signature: Karen Sue Gibson
Date Submitted: 1/25/2016

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BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO

- - -

In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan.	Case No. 14-1297-EL-SSO

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PROCEEDINGS

before Mr. Gregory Price, Ms. Mandy Chiles, and Ms. Megan Addison, Attorney Examiners, and Commissioner Asim Z. Haque at the Public Utilities Commission of Ohio, 180 East Broad Street, Room 11-A, Columbus, Ohio, called at 9:00 a.m. on Thursday, January 21, 2016.

- - -

VOLUME XL

- - -

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PJM Load Forecast Report
January 2016

Prepared by PJM Resource Adequacy Planning Department

EXHIBIT
COMPANIES
177

2016 PJM LOAD FORECAST REPORT

EXECUTIVE SUMMARY

- This report presents an independent load forecast prepared by PJM staff.

- The report includes long-term forecasts of peak loads, net energy, load management and energy efficiency for each PJM zone, region, locational deliverability area, and the total RTO.

- All load models were estimated with historical data from January 1994 through August 2015. The models were simulated with weather data from years 1994 through 2014, generating 273 scenarios. The economic forecast used was Moody's Analytics' October 2015 release. Equipment indexes reflect the 2015 update of Itron's end-use data, which is consistent with the Energy Information Administration's 2015 Annual Energy Outlook.

- Table B-8 has been modified; it now represents the amount of distributed solar generation subtracted from each forecast year. These values reflect the impact of historical distributed solar generation at peak and reflect the forecasted amount of solar additions at peak in each forecast year. These values are included in Tables B-1 through B-6 and Tables B-10 and B-11.

- Since the 2015 report, PJM has significantly revised its load forecast model. The treatment of weather has been revised to provide more variable load response to weather across a wider range of conditions. Three variables (cooling, heating, and other) were added to account for trends in equipment/appliance saturation and efficiency, and distributed solar generation is now reflected in the historical load data used to estimate the models, with a separately-derived solar forecast used to adjust load forecasts.

- The economic regions used for each zone have been revised to be consistent with the revised definitions of metropolitan areas of the U.S. Office of Management and Budget. An exception is DOM zone, for which economic data for the Commonwealth of Virginia is now used. Weather station mixtures have been revised for AEP, EKPC, and PL zones.

- PJM has also significantly revised its process for developing the weather-normalized peaks that appear in the report. The new process involves estimating each zone's load and weather relationship for each season and evaluating that relationship at typical peak day weather conditions.

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- The forecasts of the following zones have been adjusted to account for large,unanticipated load changes (see Table B-9 for details):
  - The forecast of the APS zone has been adjusted to account for accelerating load related to natural gas processing plants, adding 120-280 MW from 2016 through 2020 before declining to 200 MW in 2030.
  - The forecast of the DOM zone has been adjusted to account for substantial on-going growth in data center construction, which adds 240-1,050 MW to the summer peak beginning in 2016.

- The PJM RTO weather normalized summer peak for 2015 was 150,295 MW (using the revised normalization method). The projection for the 2016 PJM RTO summer peak is 152,165 MW, an increase of 1,870 MW, or 1.2%, from the 2015 normalized peak.

- Summer peak load growth for the PJM RTO is projected to average 0.6% per year over the next 10 years, and 0.6% over the next 15 years. The PJM RTO summer peak is forecasted to be 161,914 MW in 2026, a 10-year increase of 9,749 MW, and reaches 167,484 MW in 2031, a 15-year increase of 15,319 MW. Annualized 10-year growth rates for individual zones range from -0.1% to 1.2%.

- Winter peak load growth for PJM RTO is projected to average 0.8% per year over the next 10-year period, and 0.8% over the next 15 years. The PJM RTO winter peak load in 2025/26 is forecasted to be 14[illegible]14 MW, a 10-year increase of 10,670 MW, and reaches 146,210 MW in 2030/31, a 15-year increase of 15,966 MW. Annualized 10-year growth rates for individual zones range from 0.2% to 1.6%.

- Compared to the 2015 Load Report, the 2016 PJM RTO summer peak forecast shows the following changes for three years of interest:
  - The next delivery year – 2016 -5,747 MW (-3.6%)
  - The next PJM auction year – 2019 -5,622 MW (-3.5%)
  - The next RTEP study year – 2021 -8,369 MW (-5.0%)

- Assumptions for future Load Management (LM) have ? from the 2015 Load Report (from approximately 1,100 MW to ? MW). Assumptions for LM use the historical amount of LM committed over the 2013/14, 2014/15 and 2015/16 Delivery Years.

NOTE:
Unless noted otherwise, all peak and energy values are non-coincident, unrestricted peaks, which represent the peak load or net energy prior to reductions for load management impacts.
All compound growth rates are calculated from the first year of the forecast.

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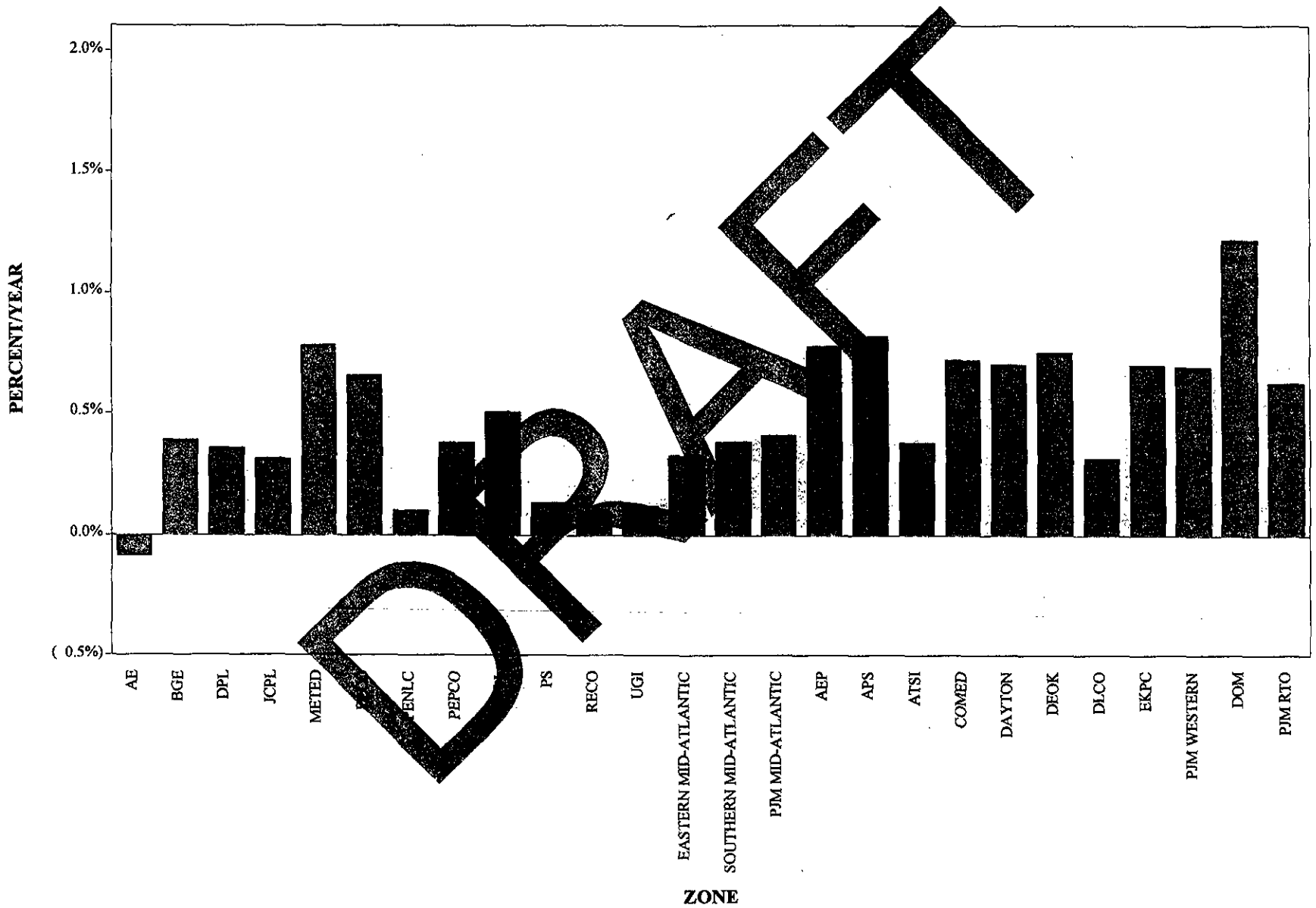
PJM SUMMER PEAK LOAD GROWTH RATE
2016 - 2026



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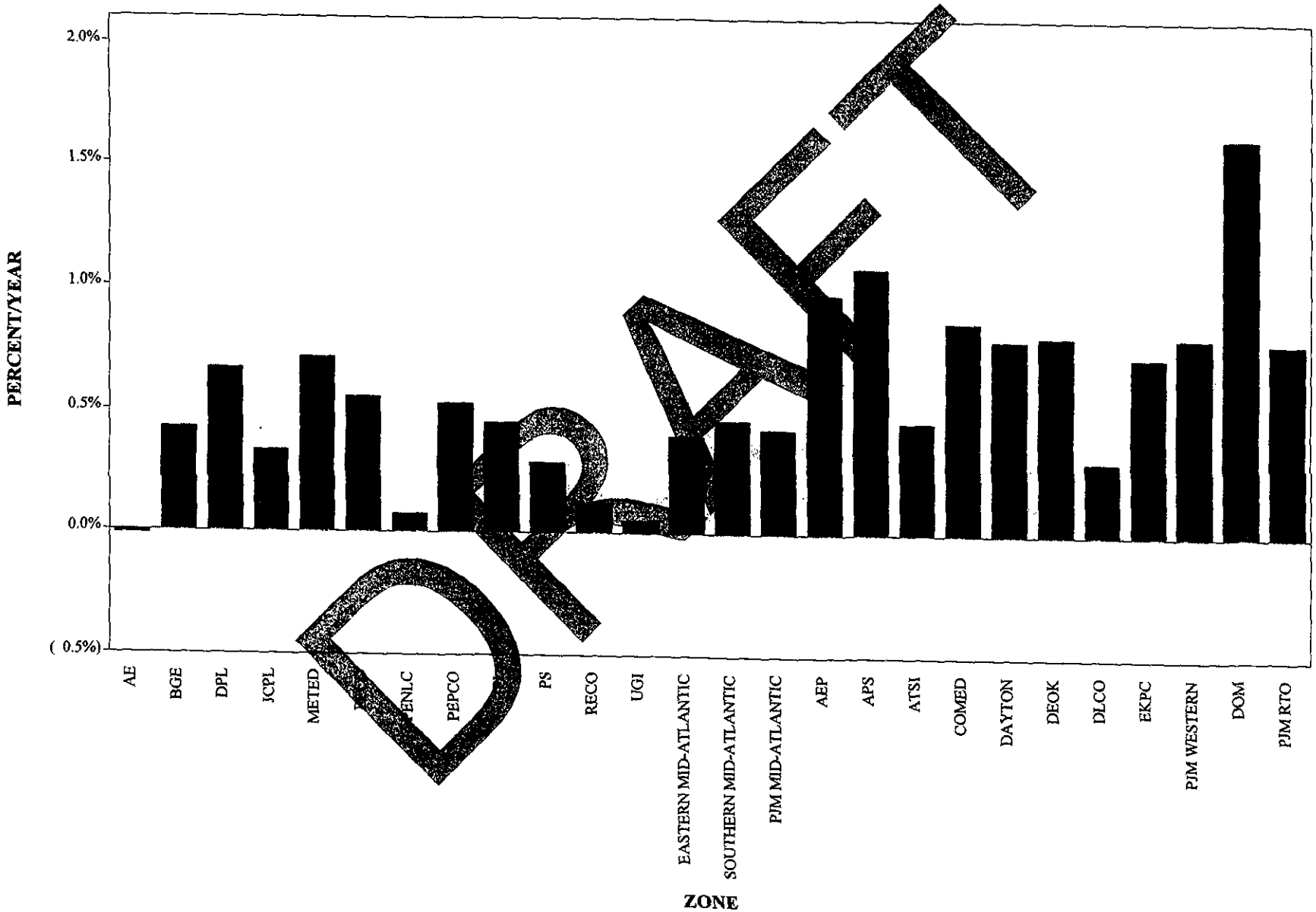
PJM WINTER PEAK LOAD GROWTH RATE
2016 - 2026



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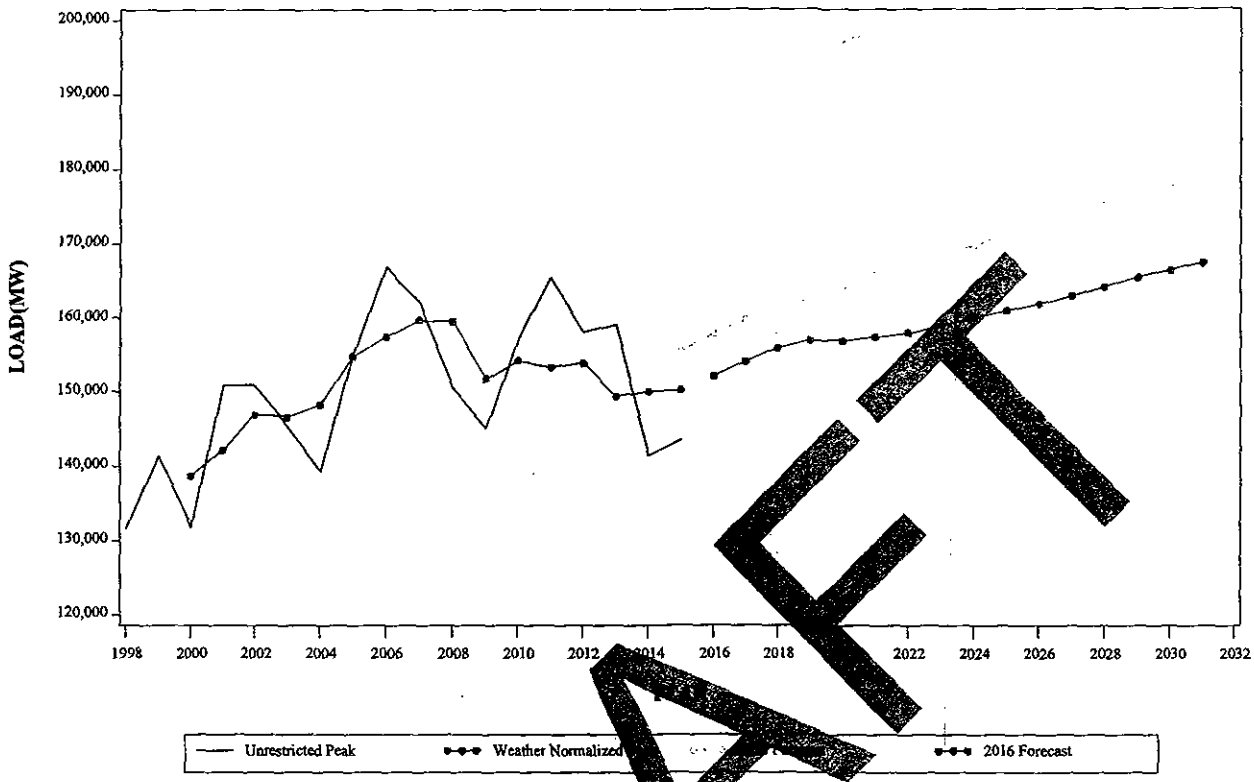
SUMMER PEAK DEMAND FOR PJM RTO GEOGRAPHIC ZONE



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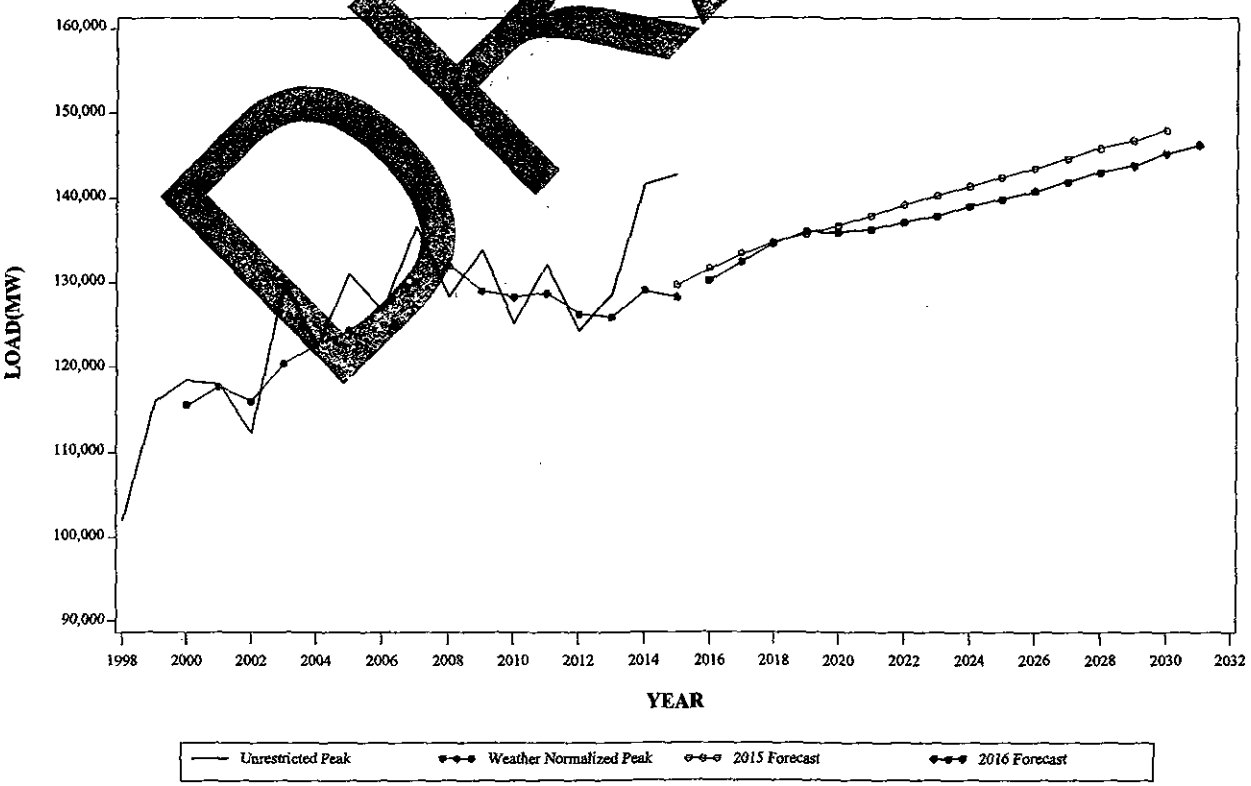

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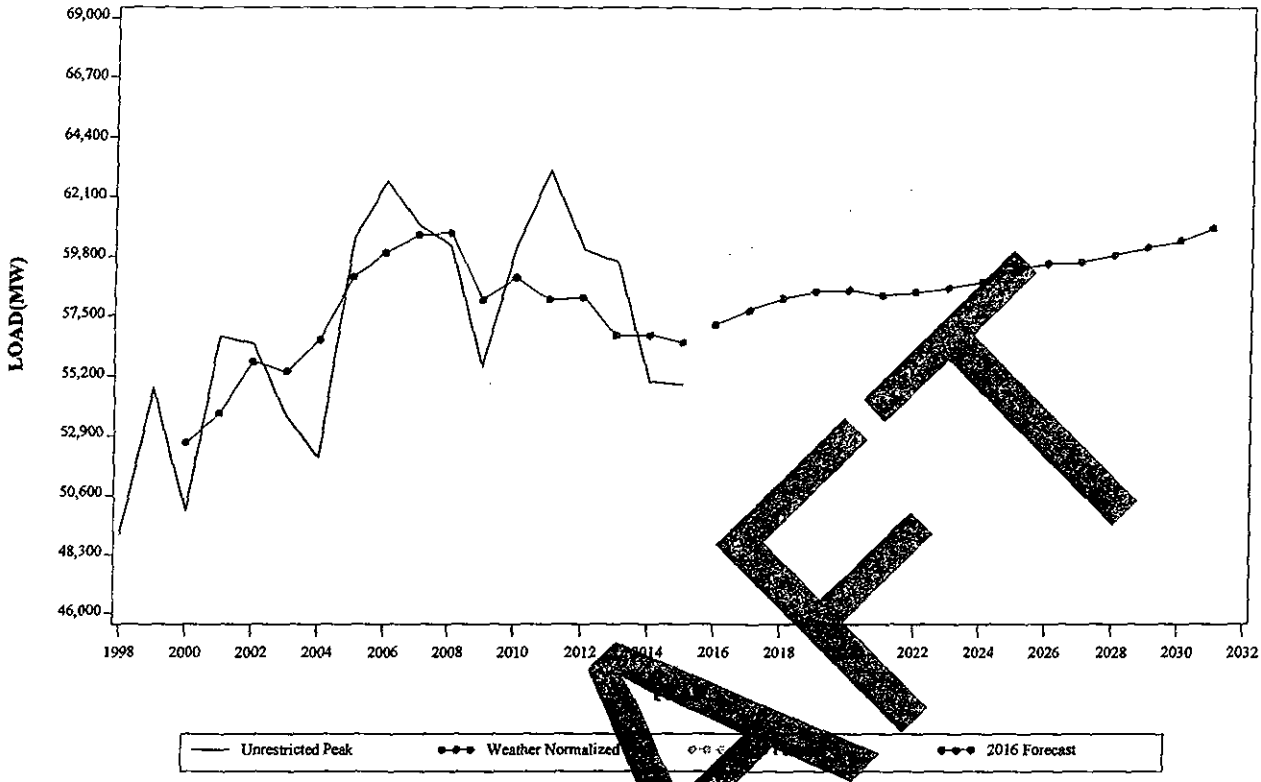

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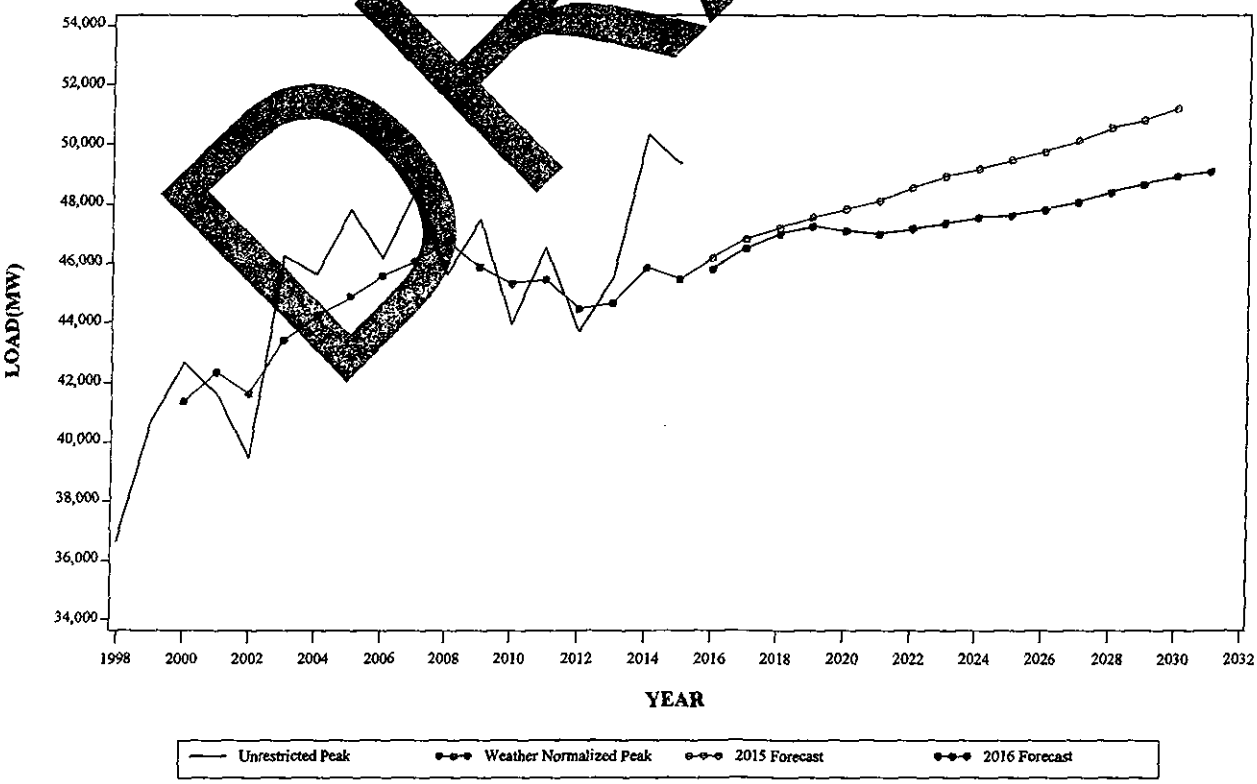

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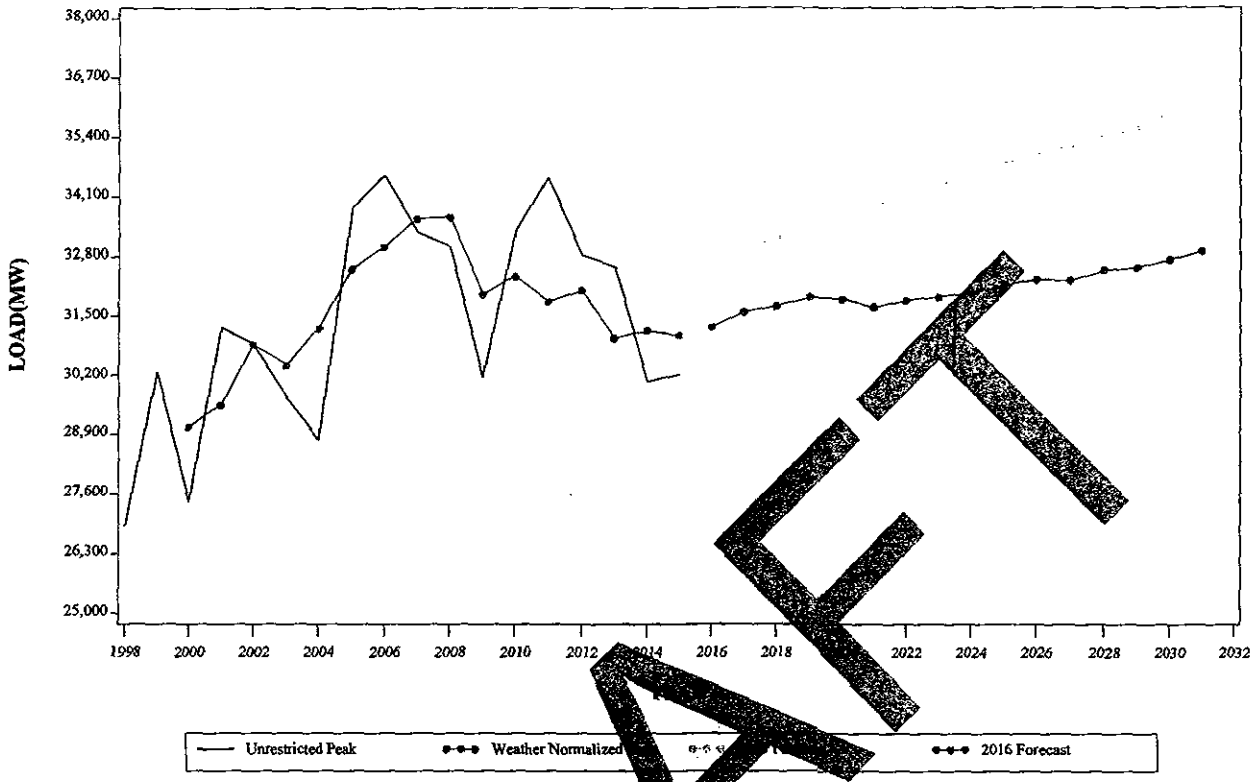

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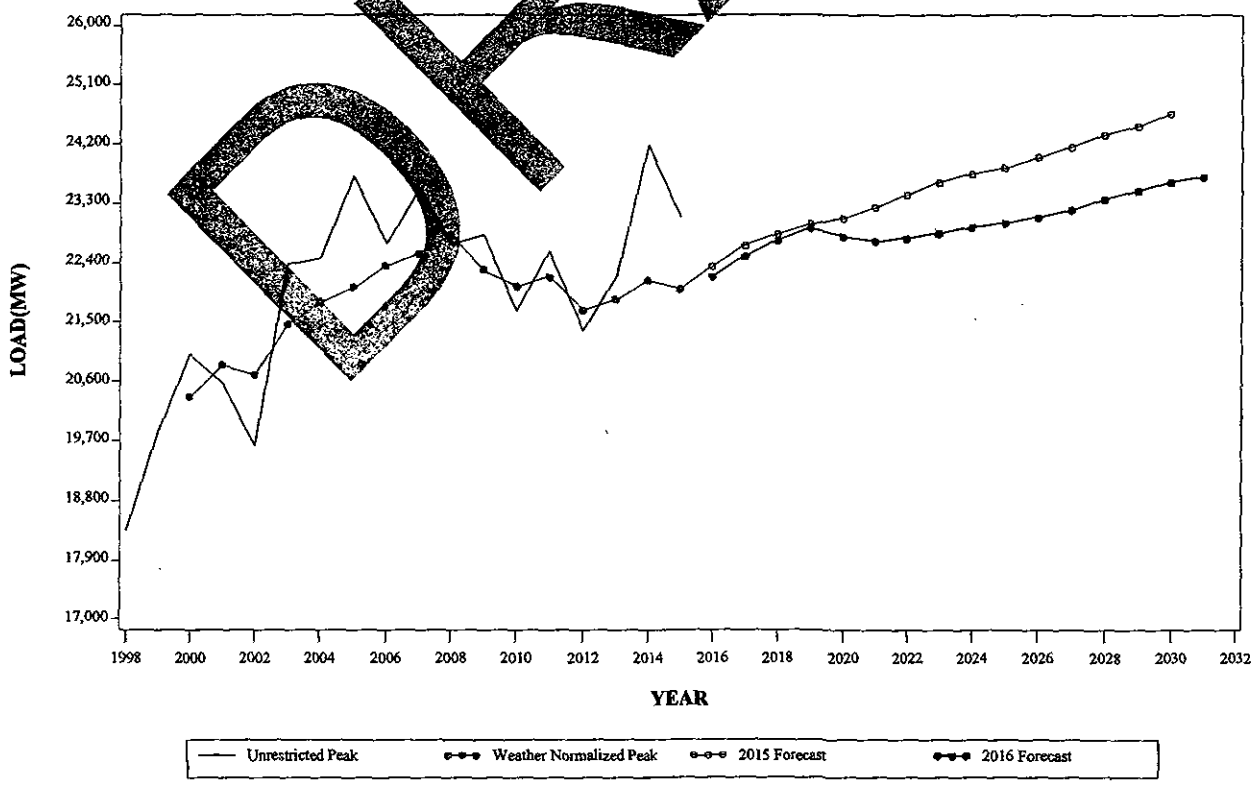

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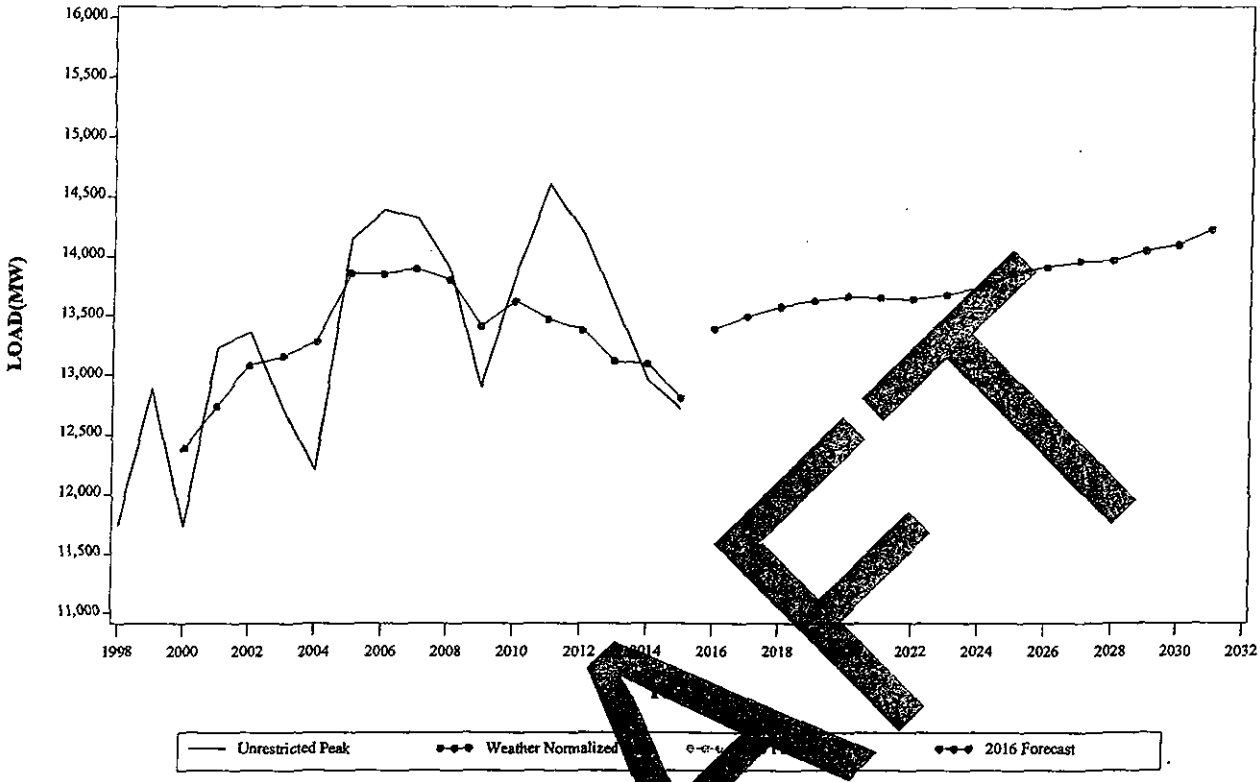

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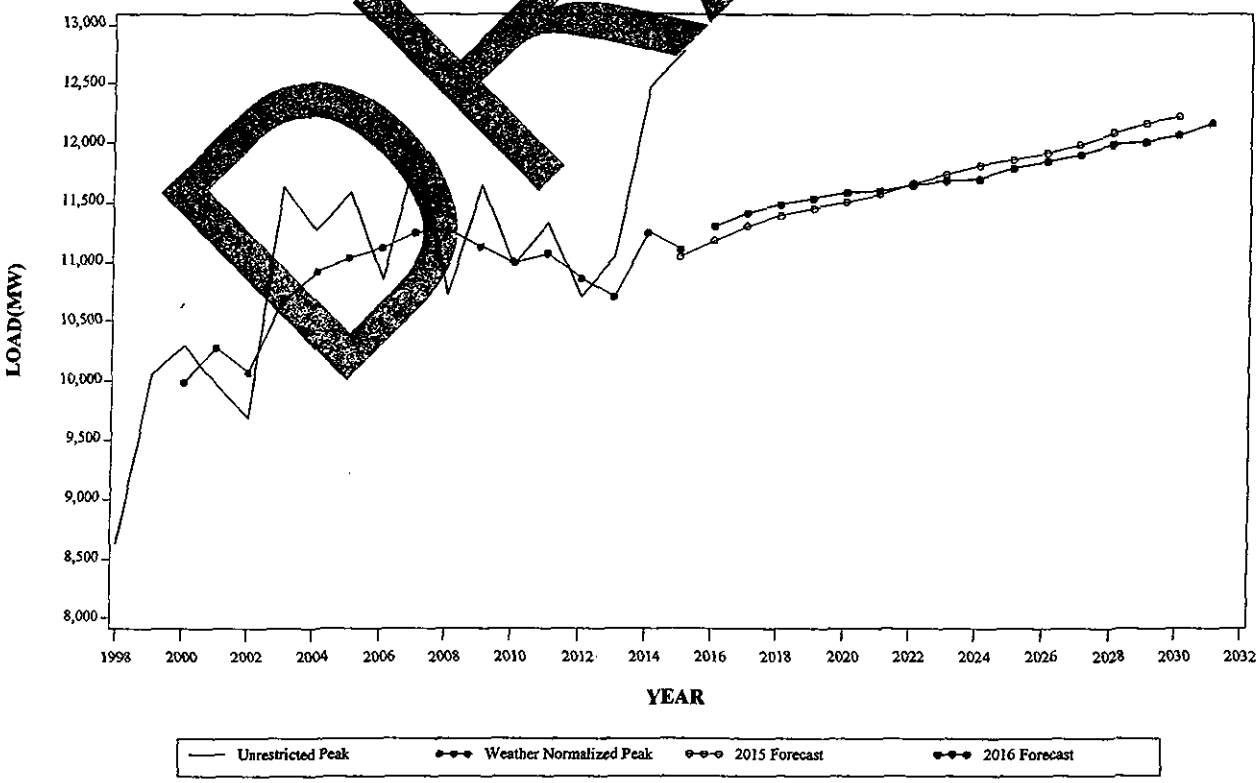

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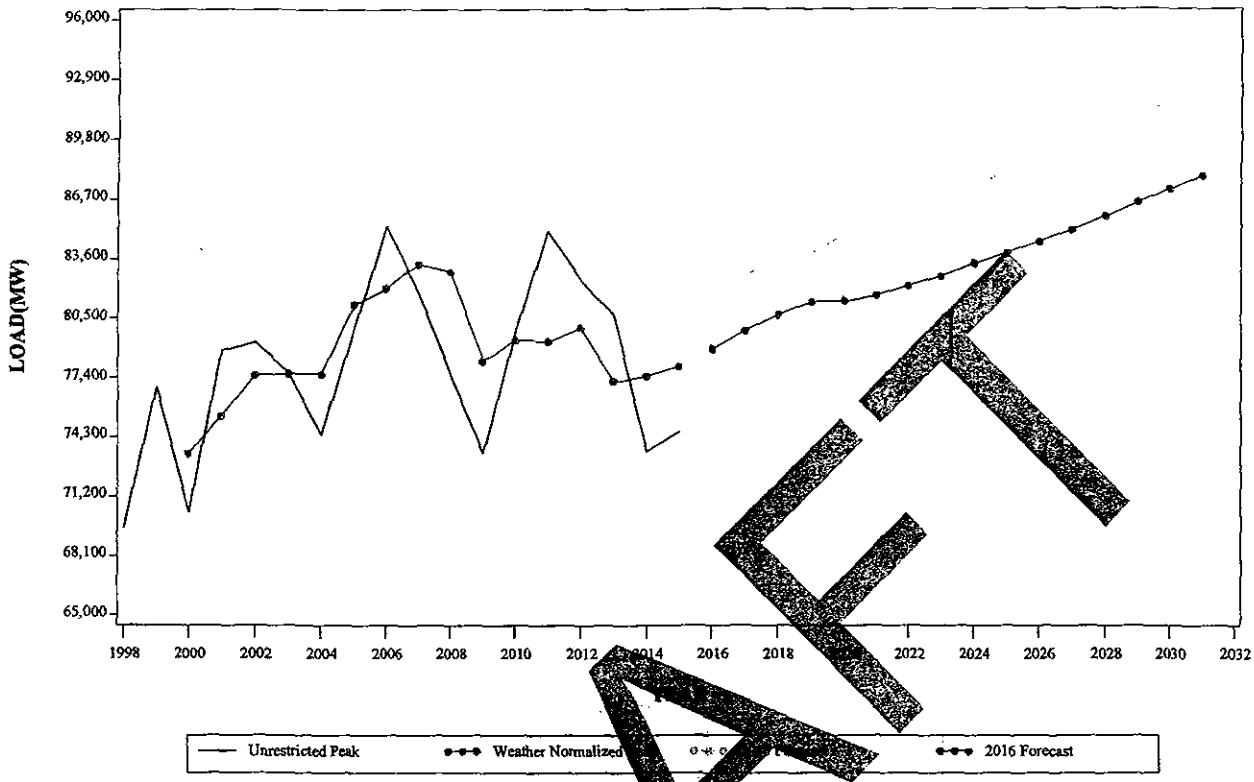

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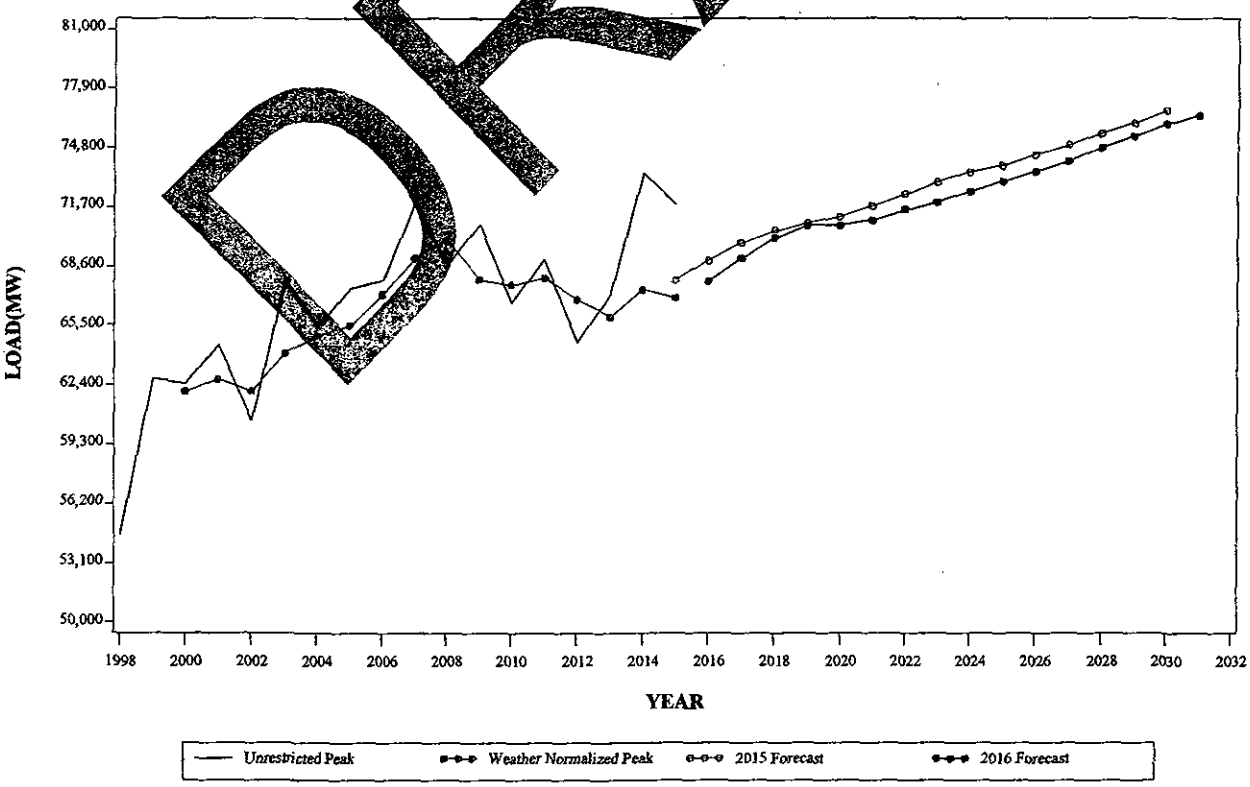

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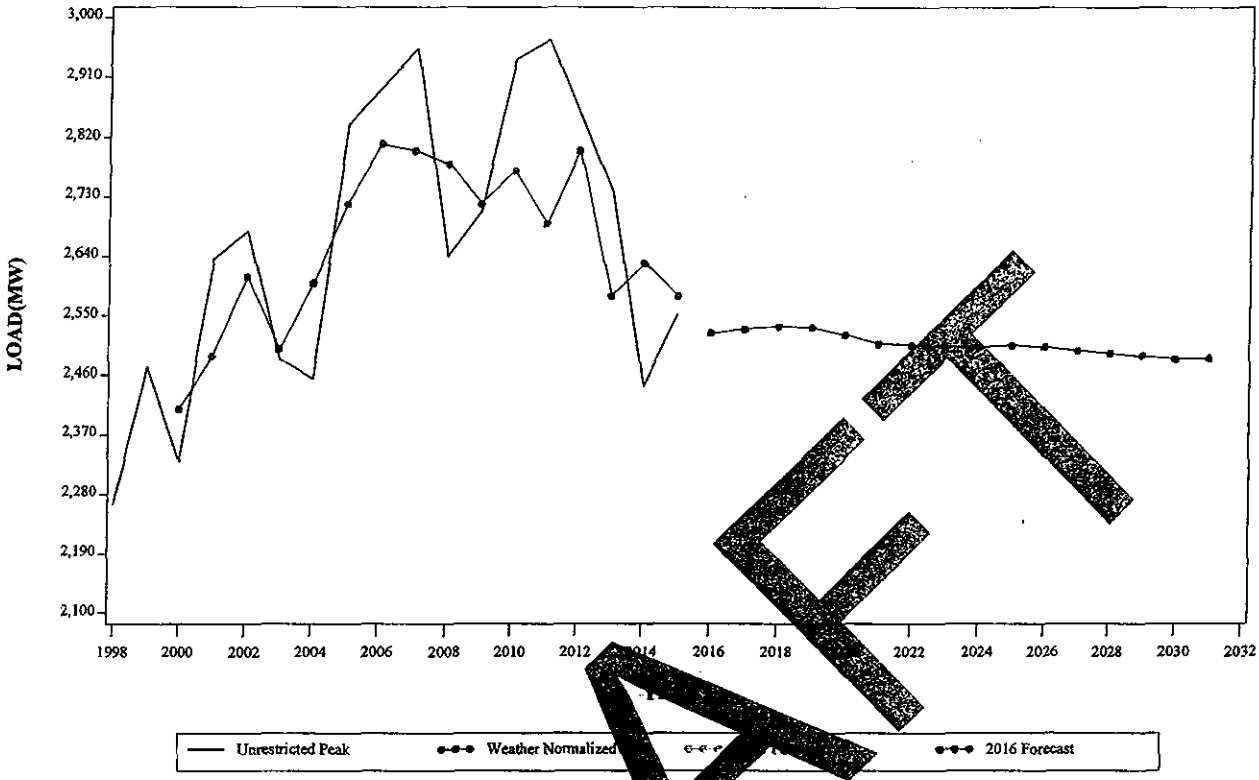

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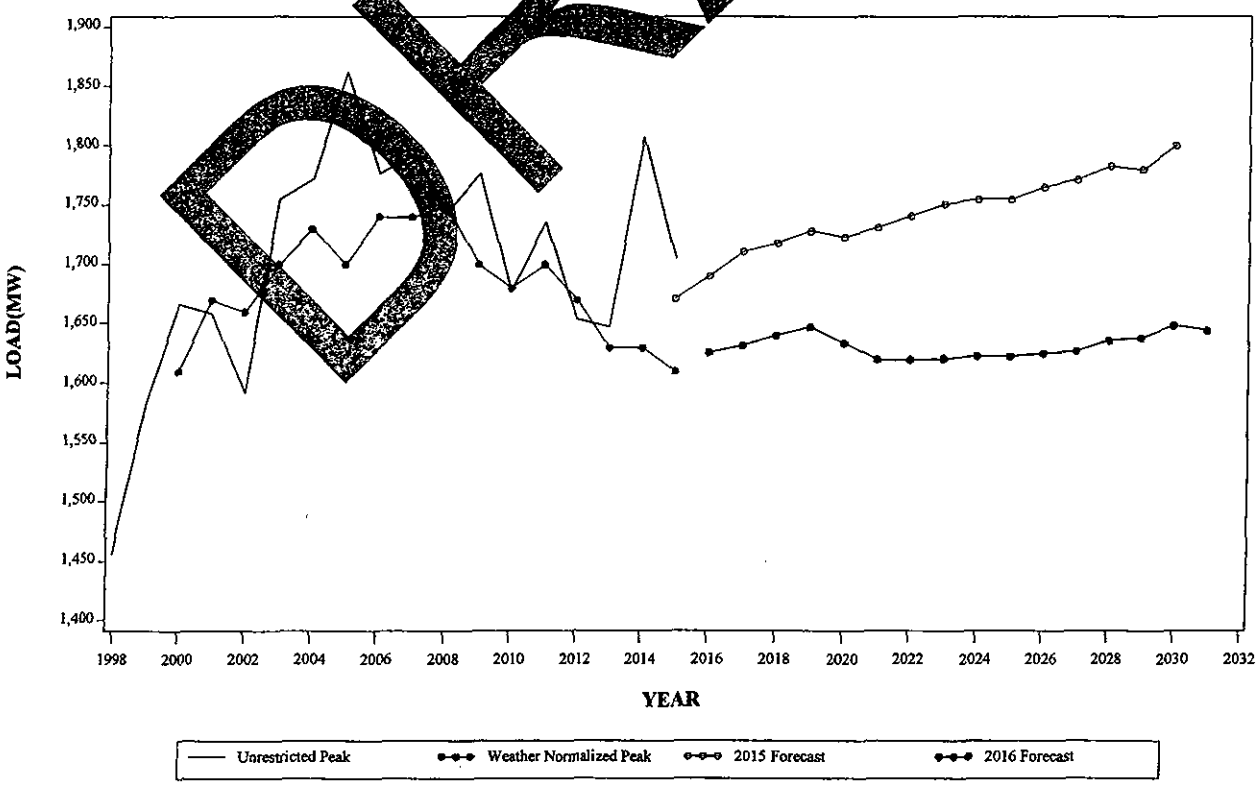

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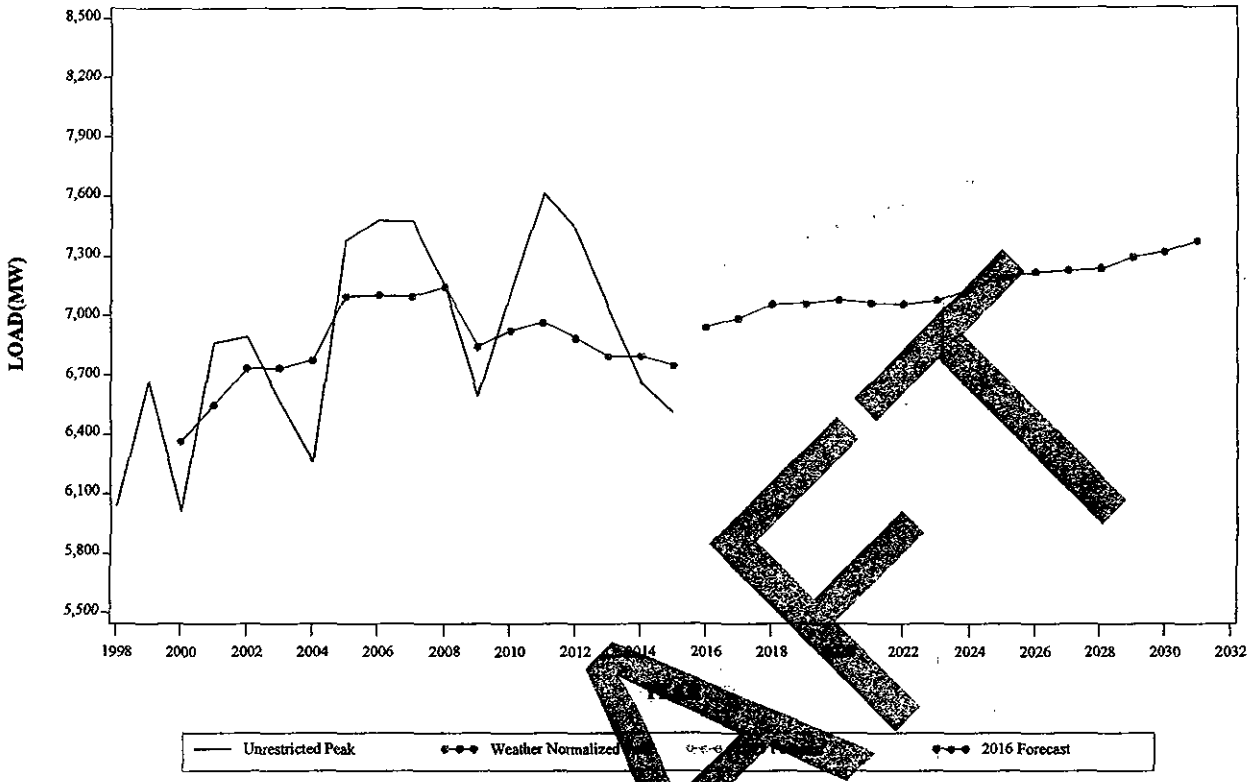

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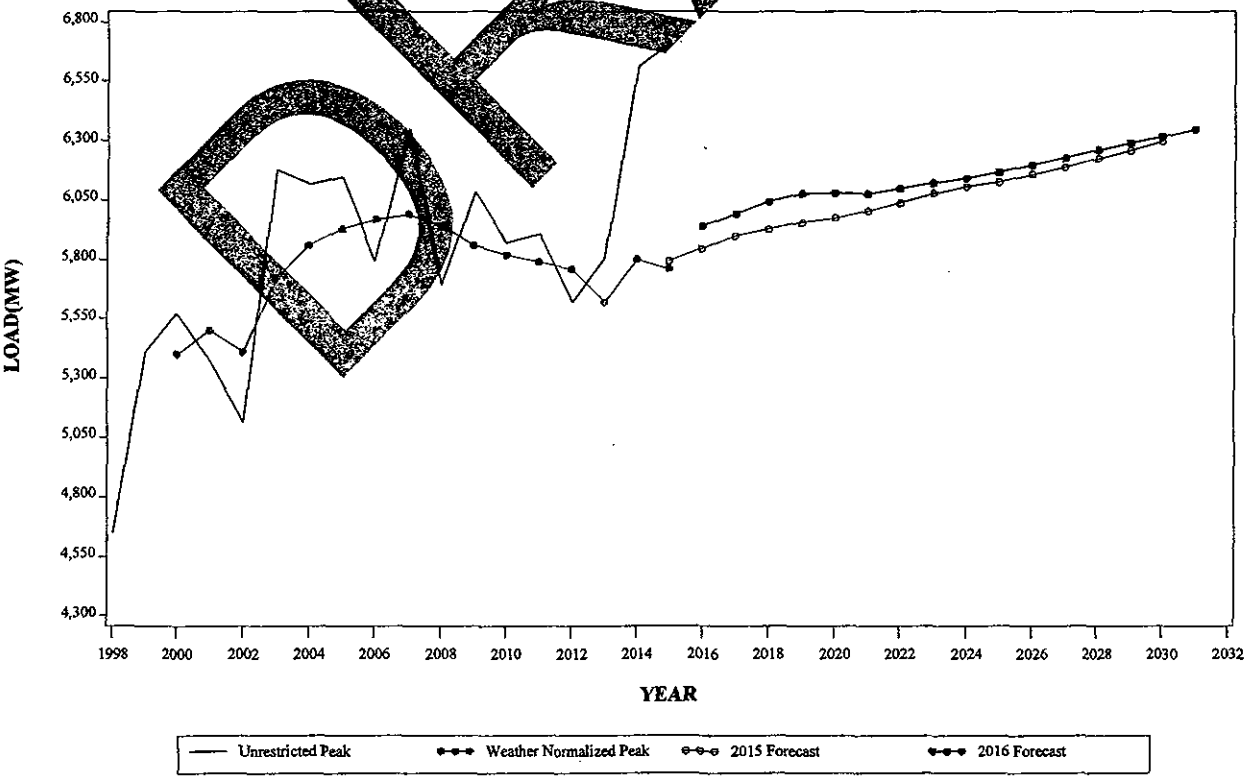

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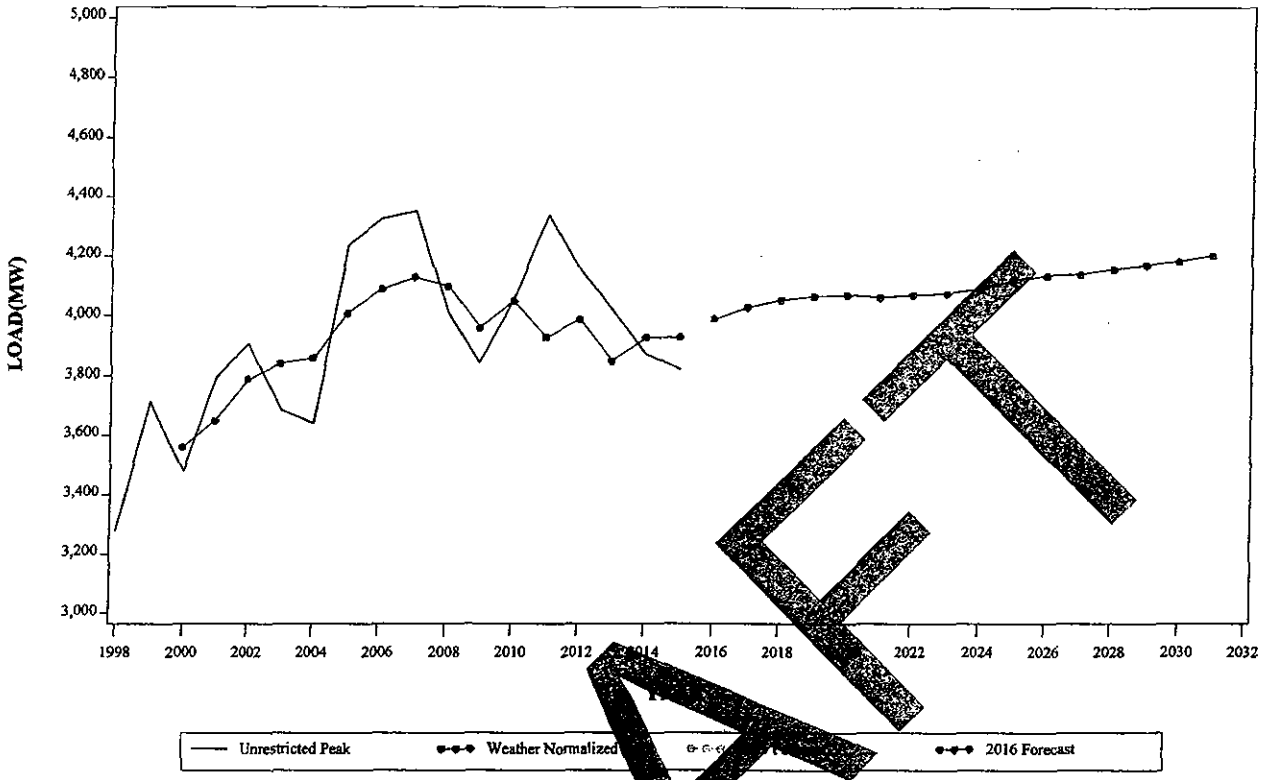

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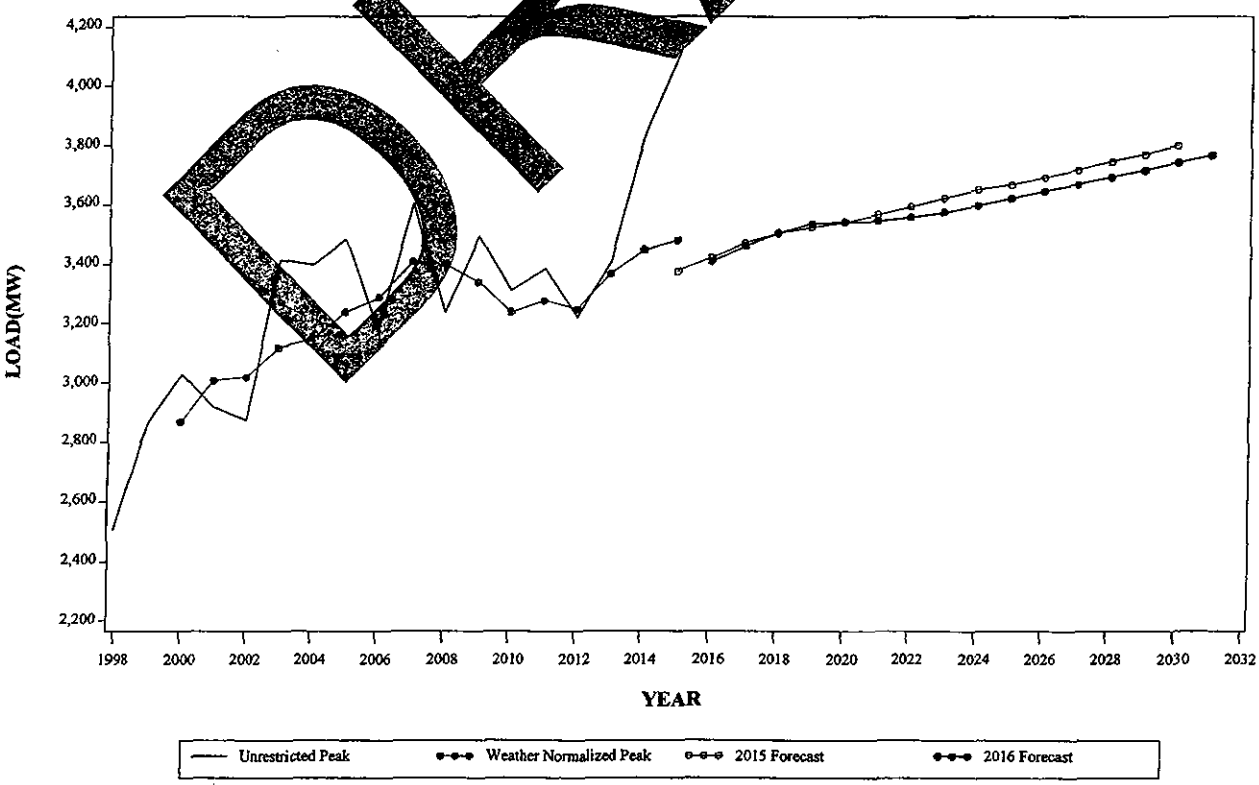

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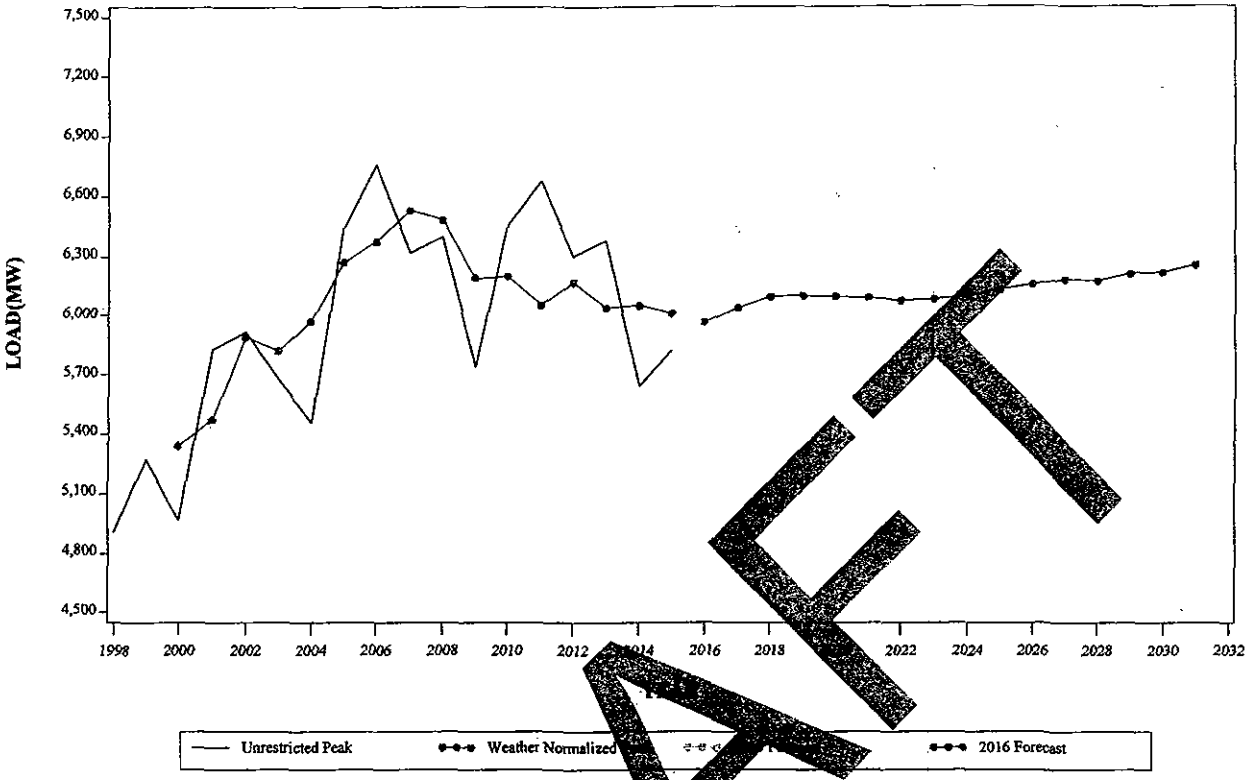

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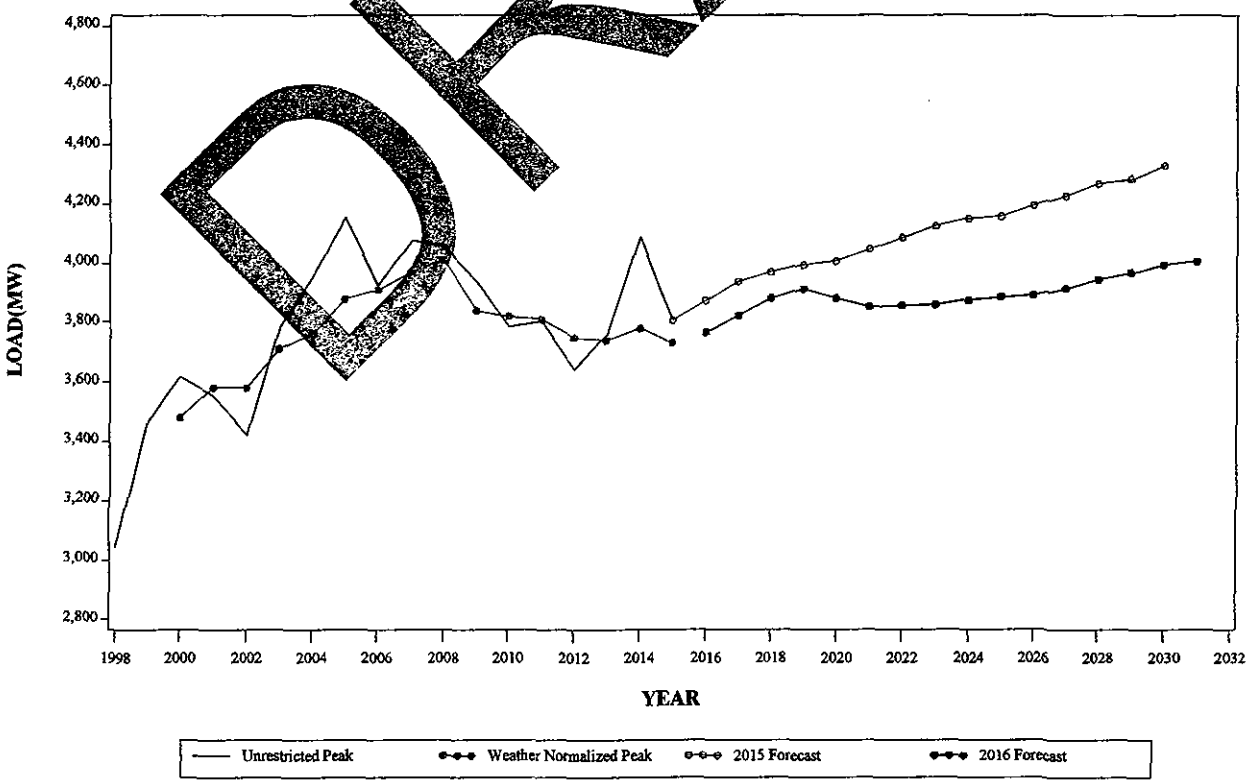

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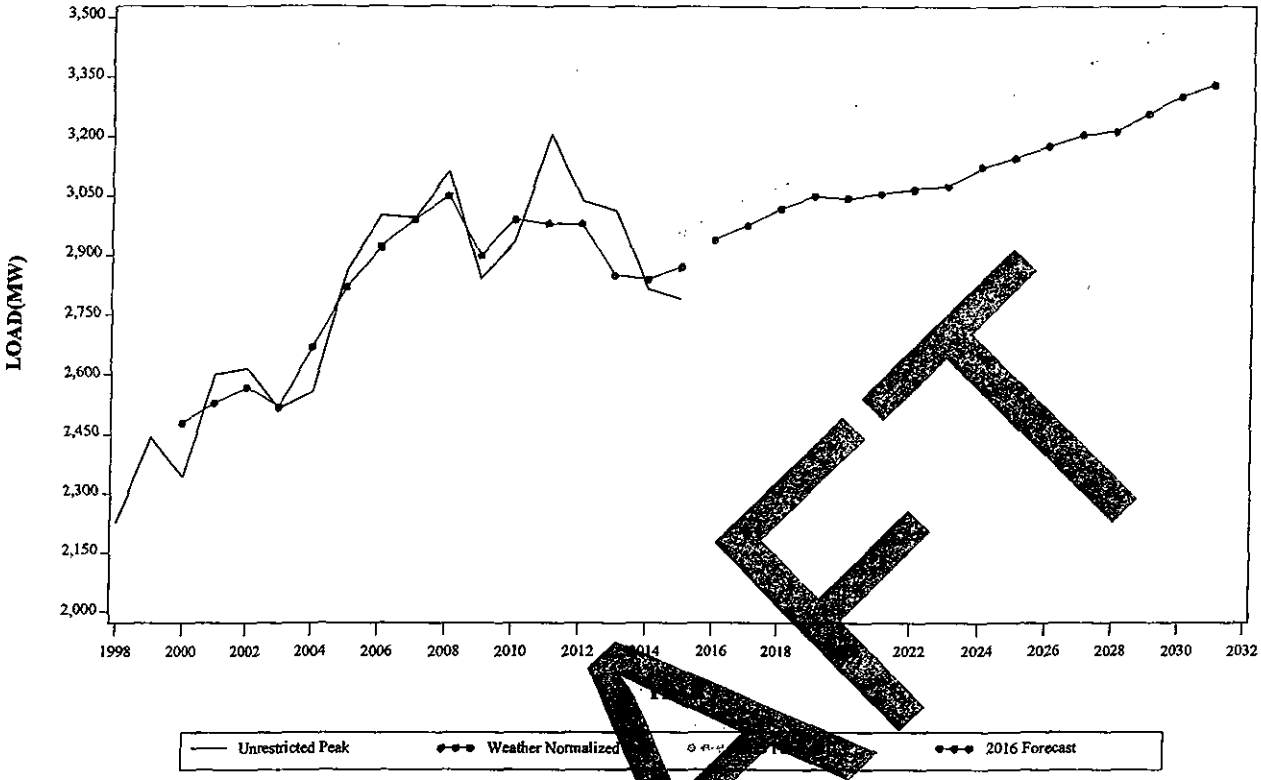

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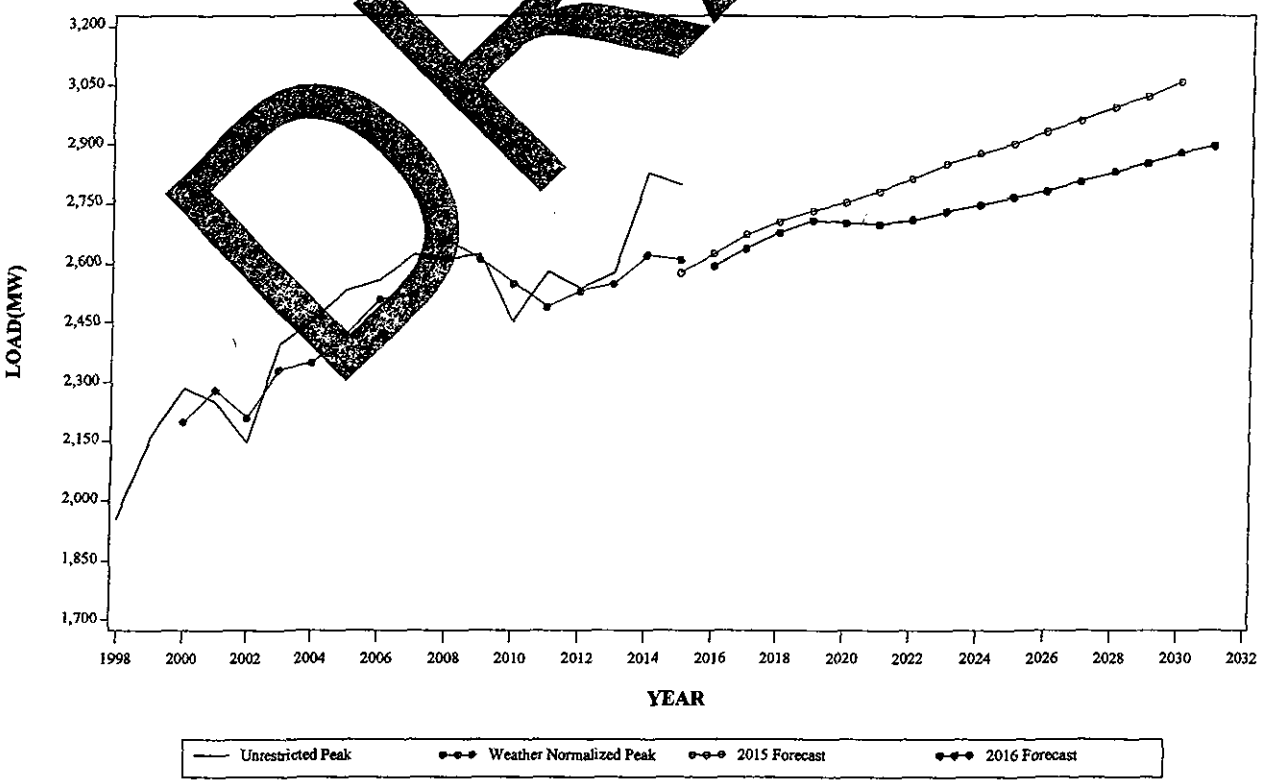

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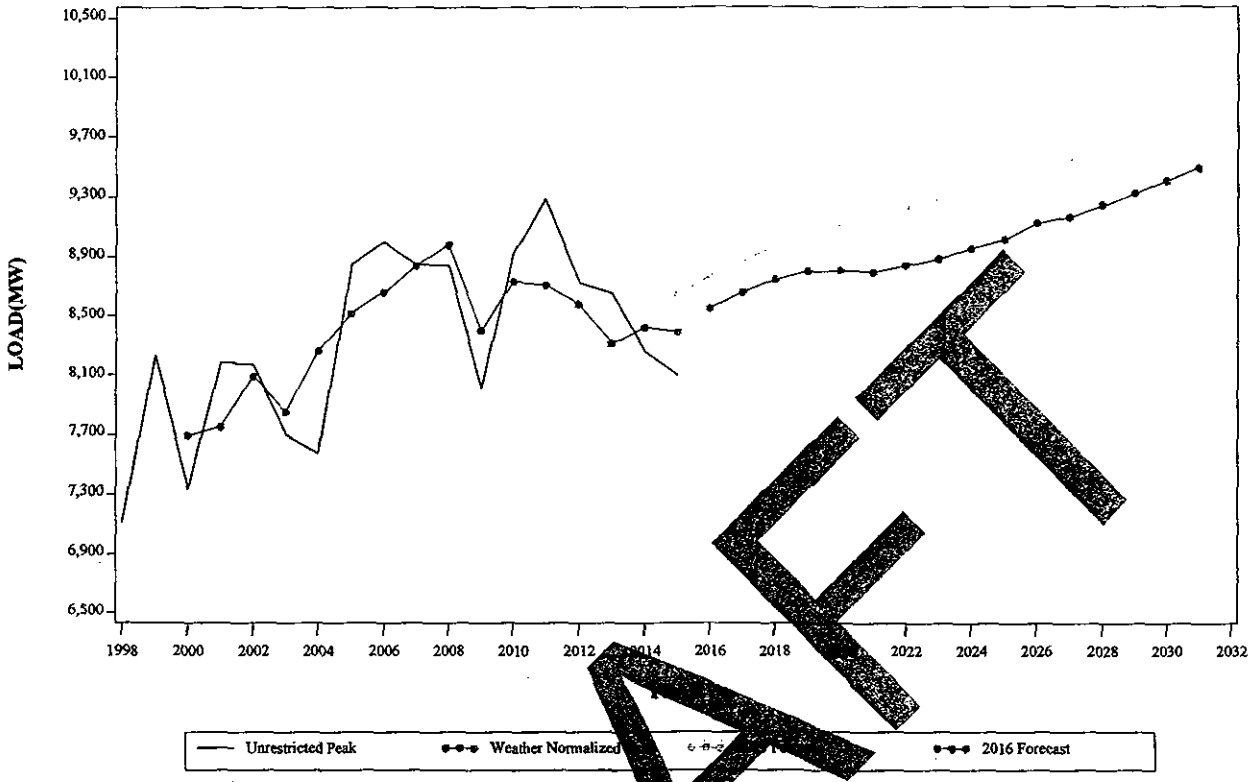

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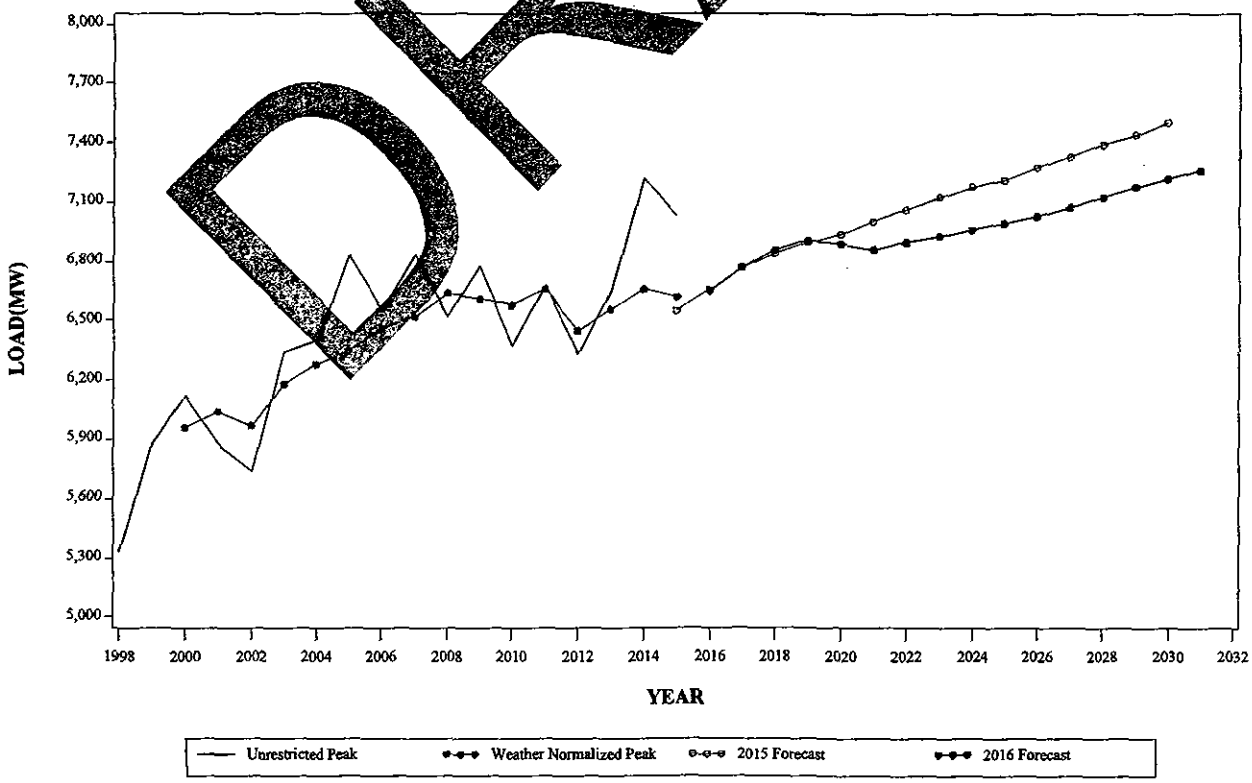

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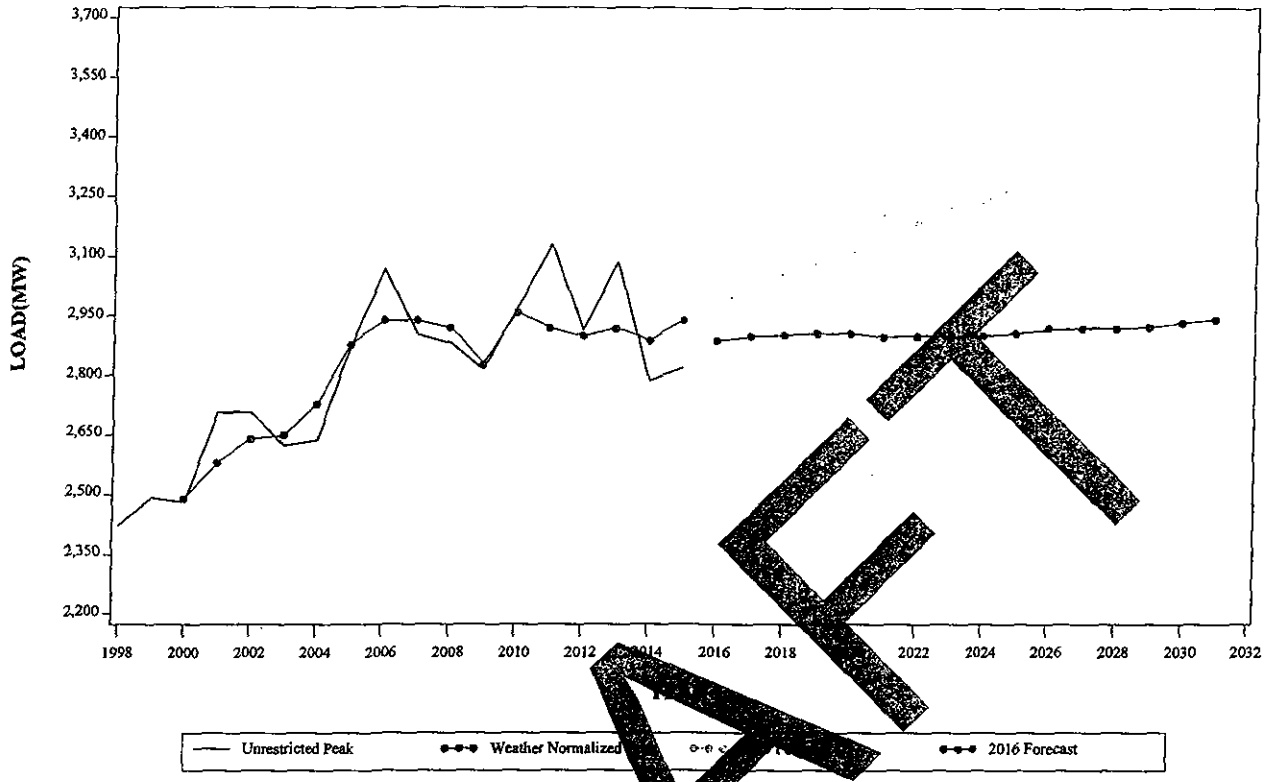

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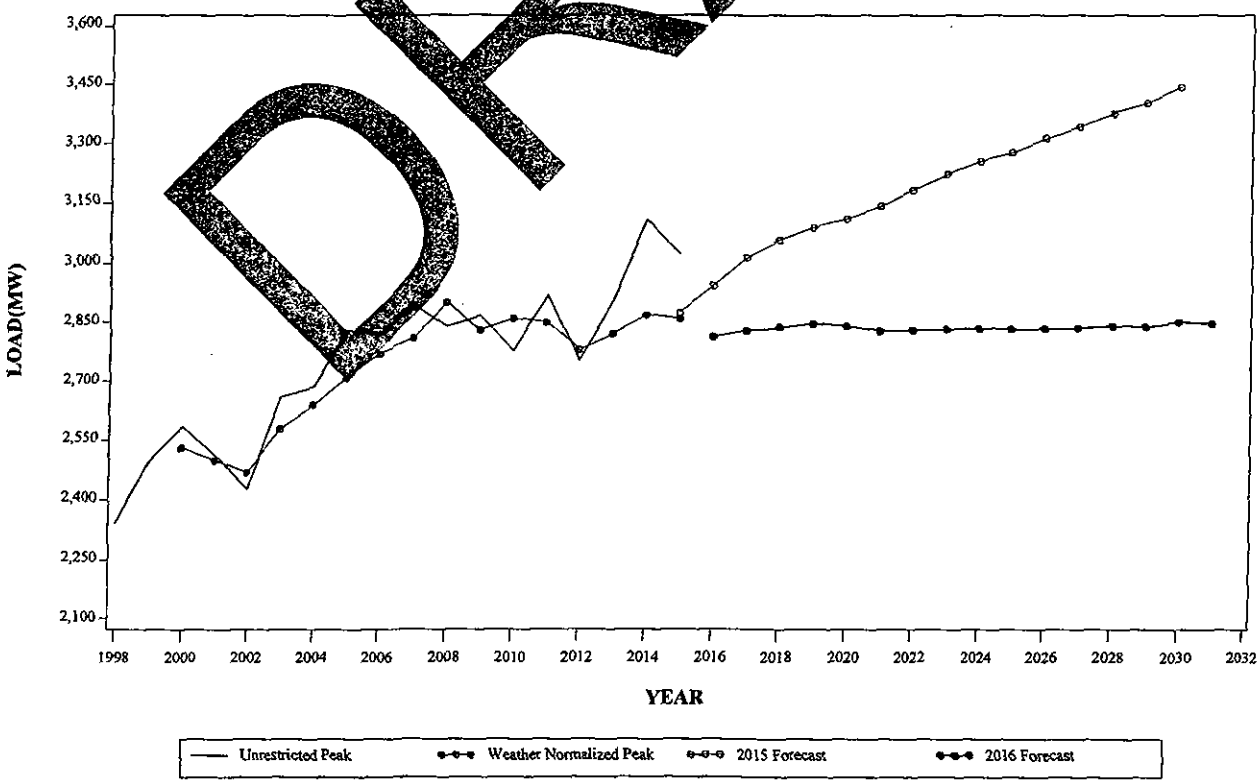

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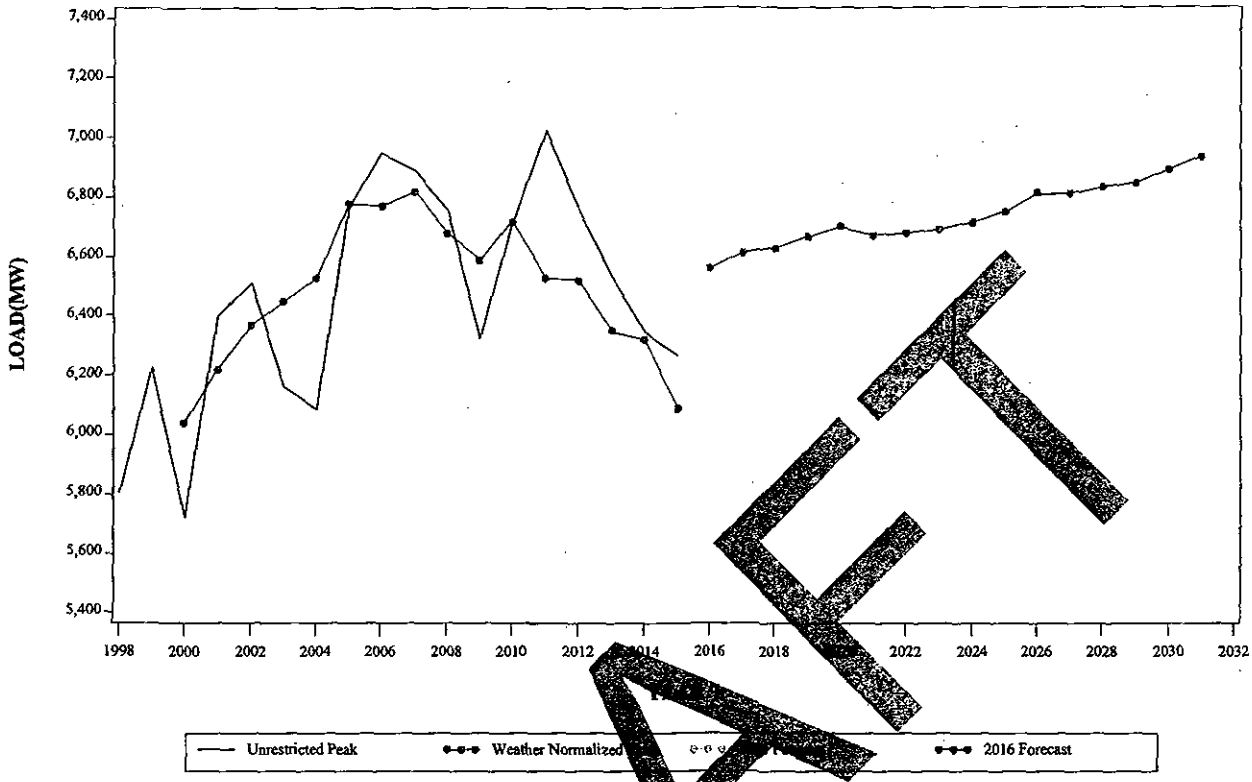

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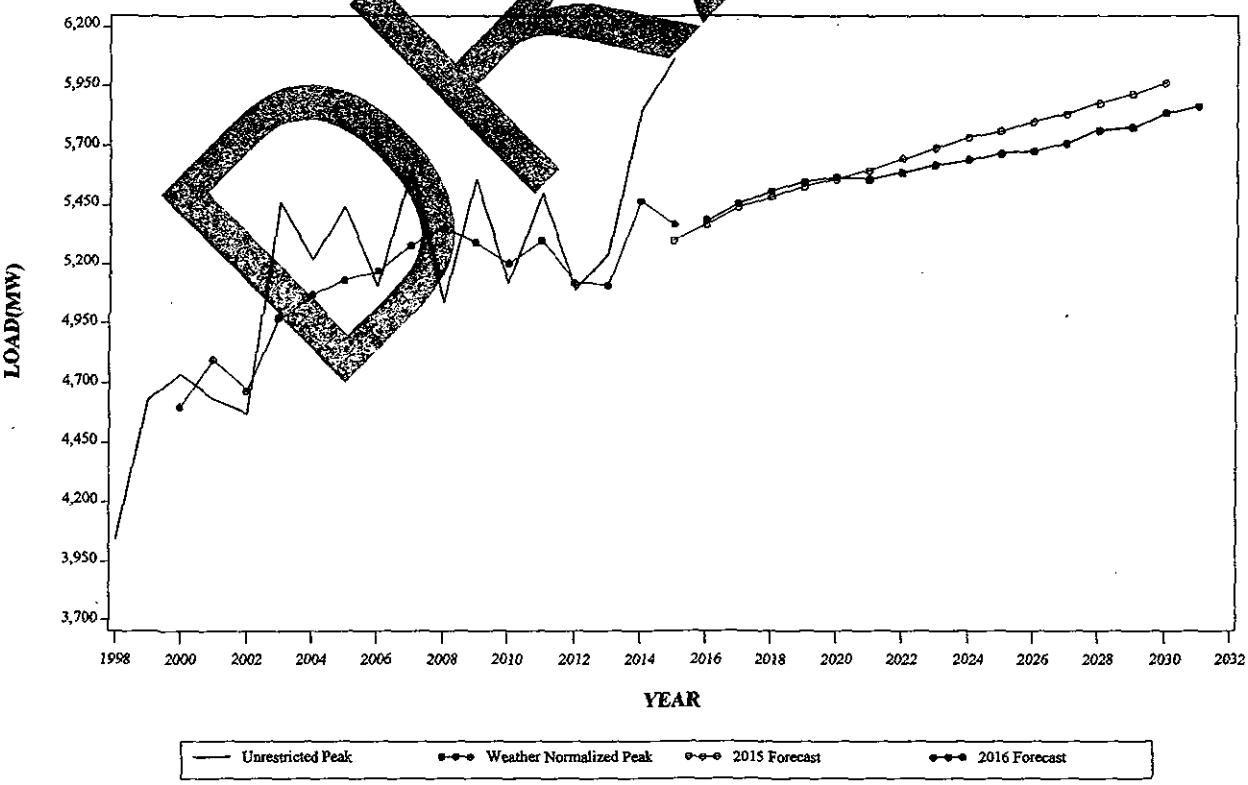

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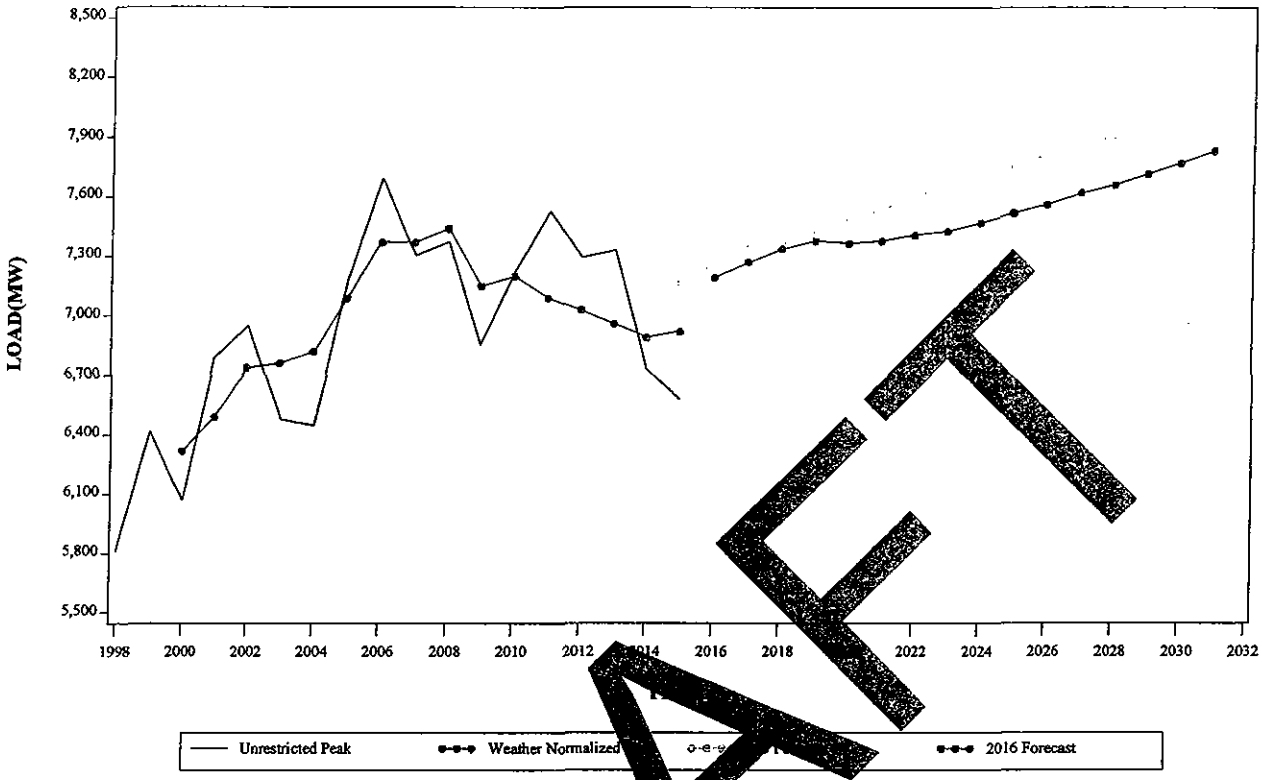

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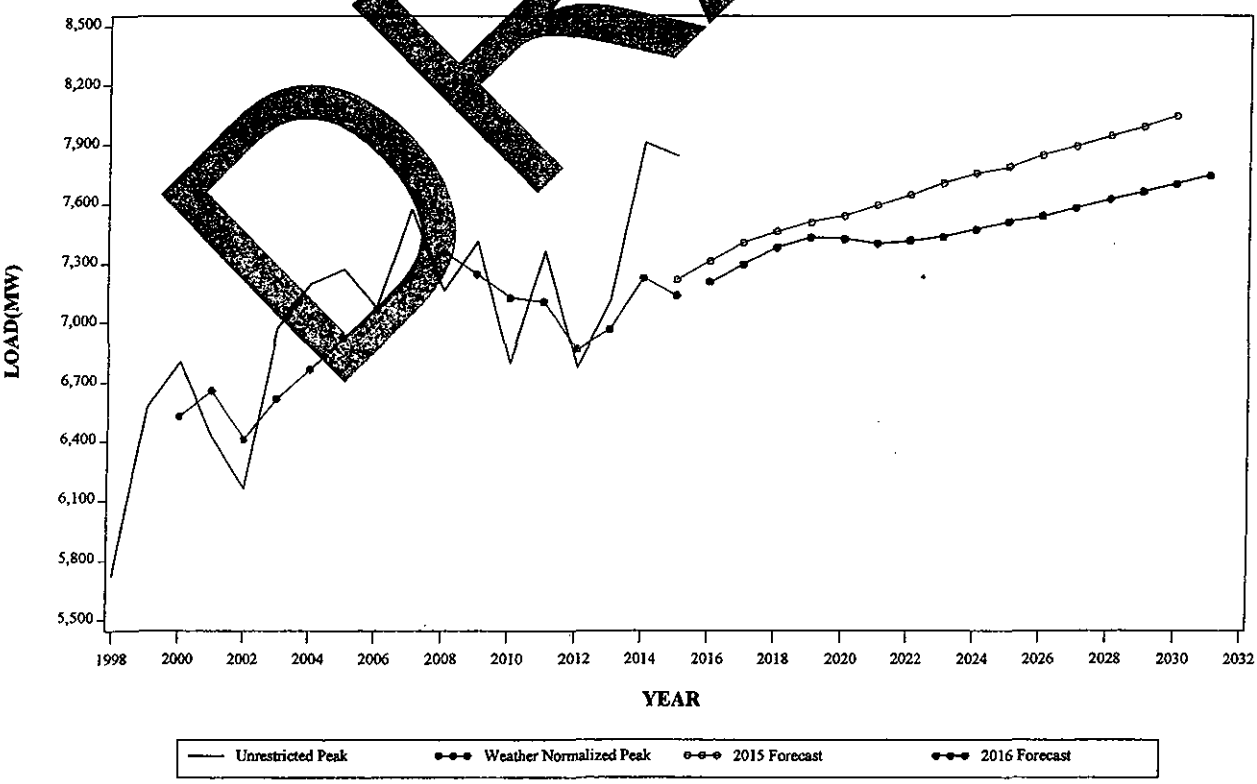

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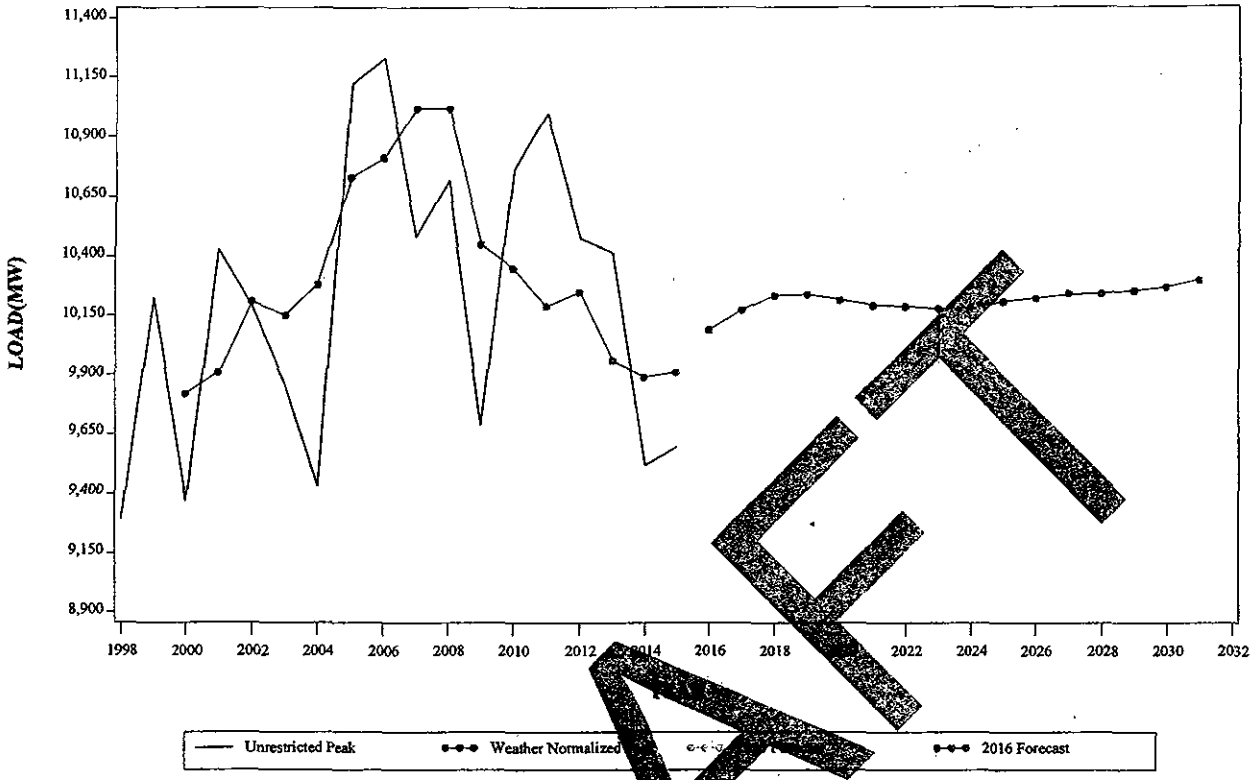

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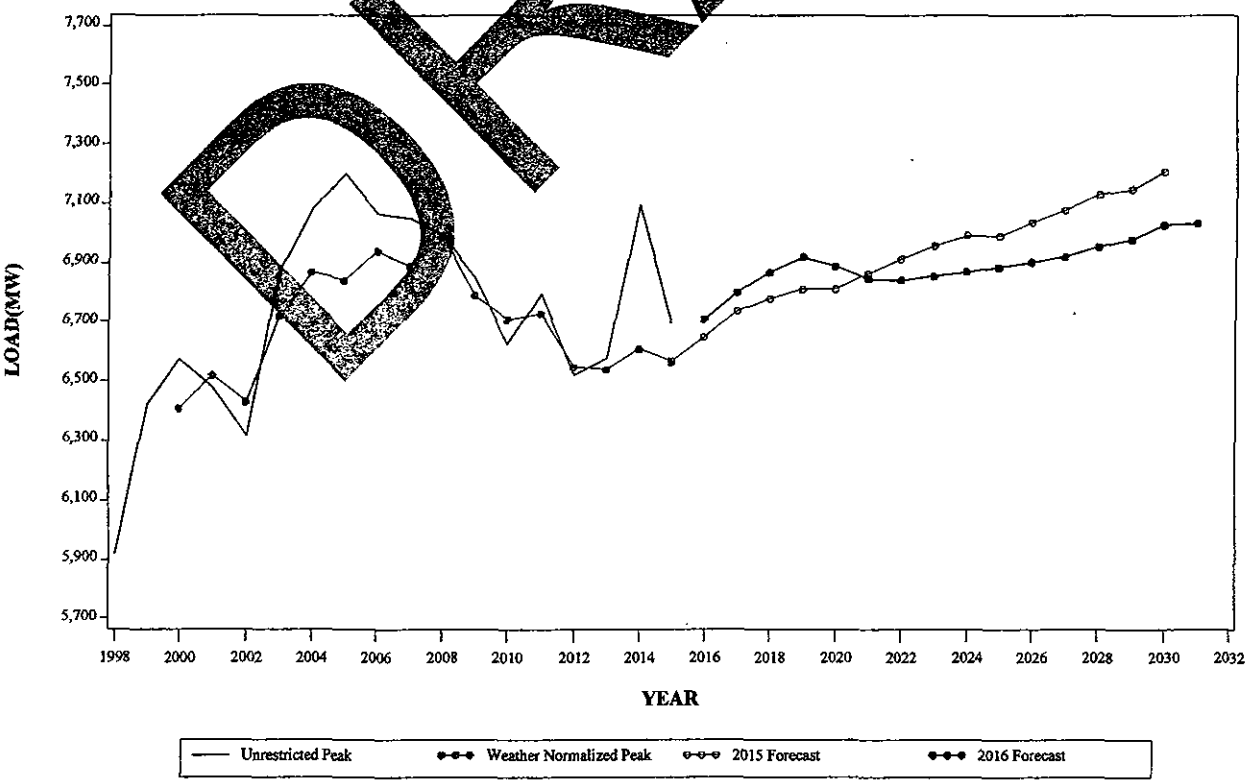

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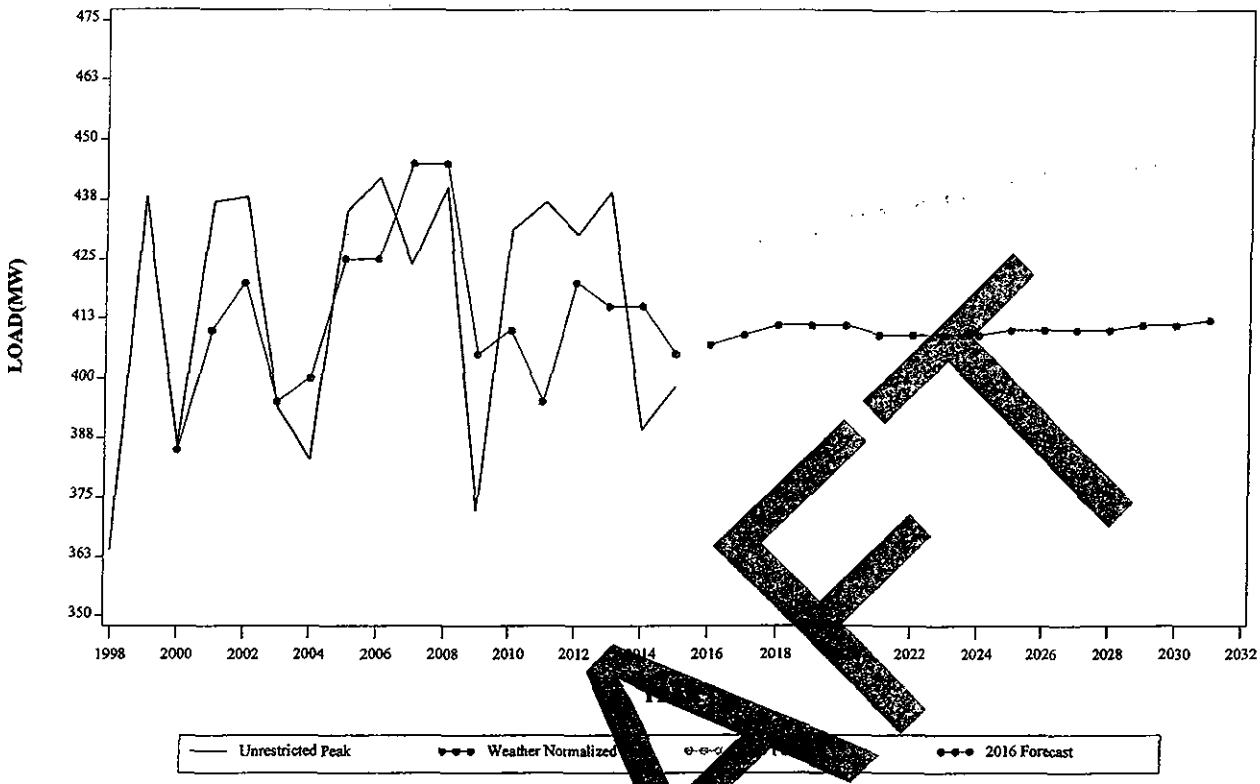

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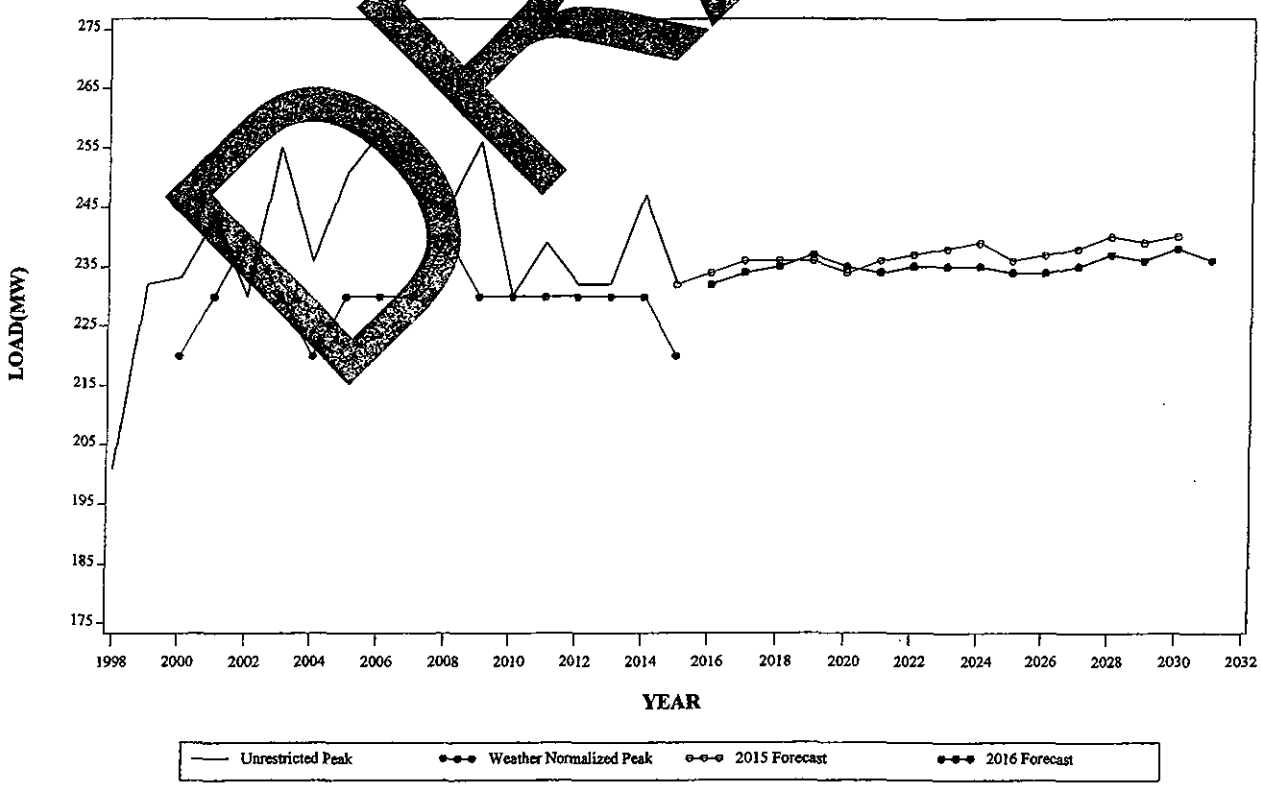

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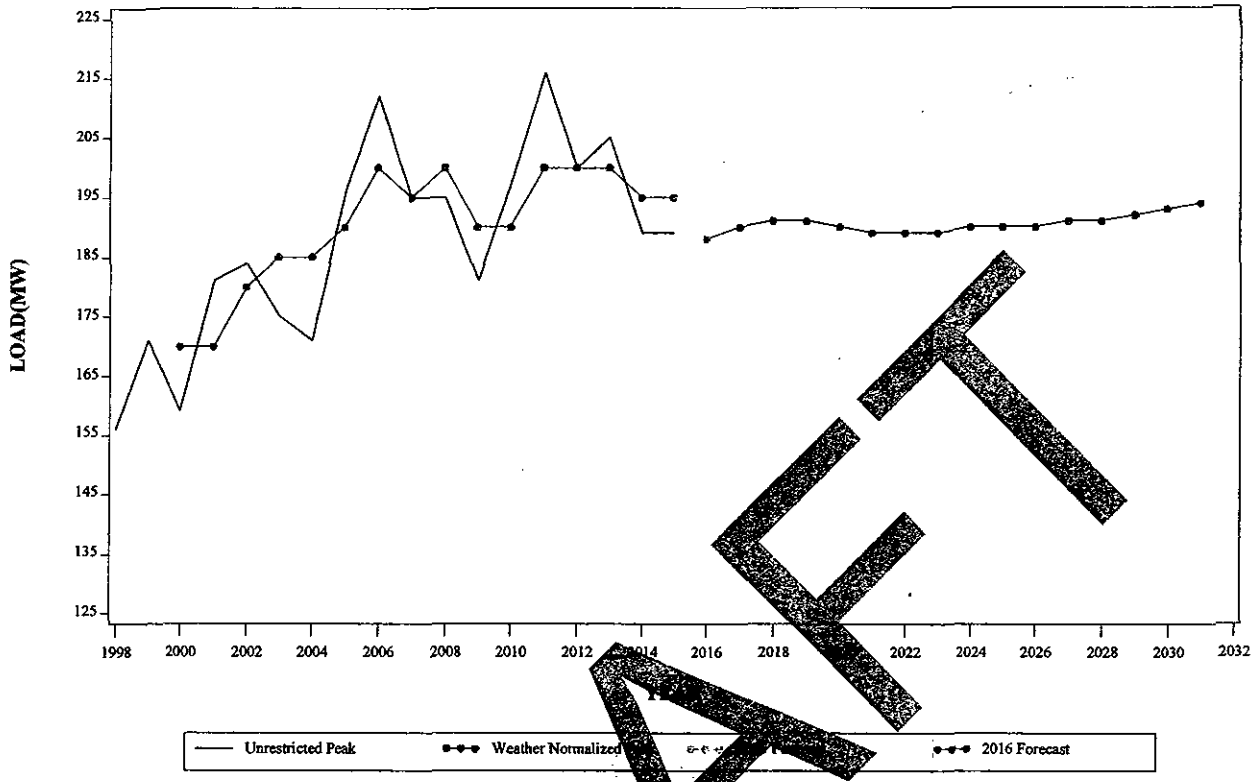

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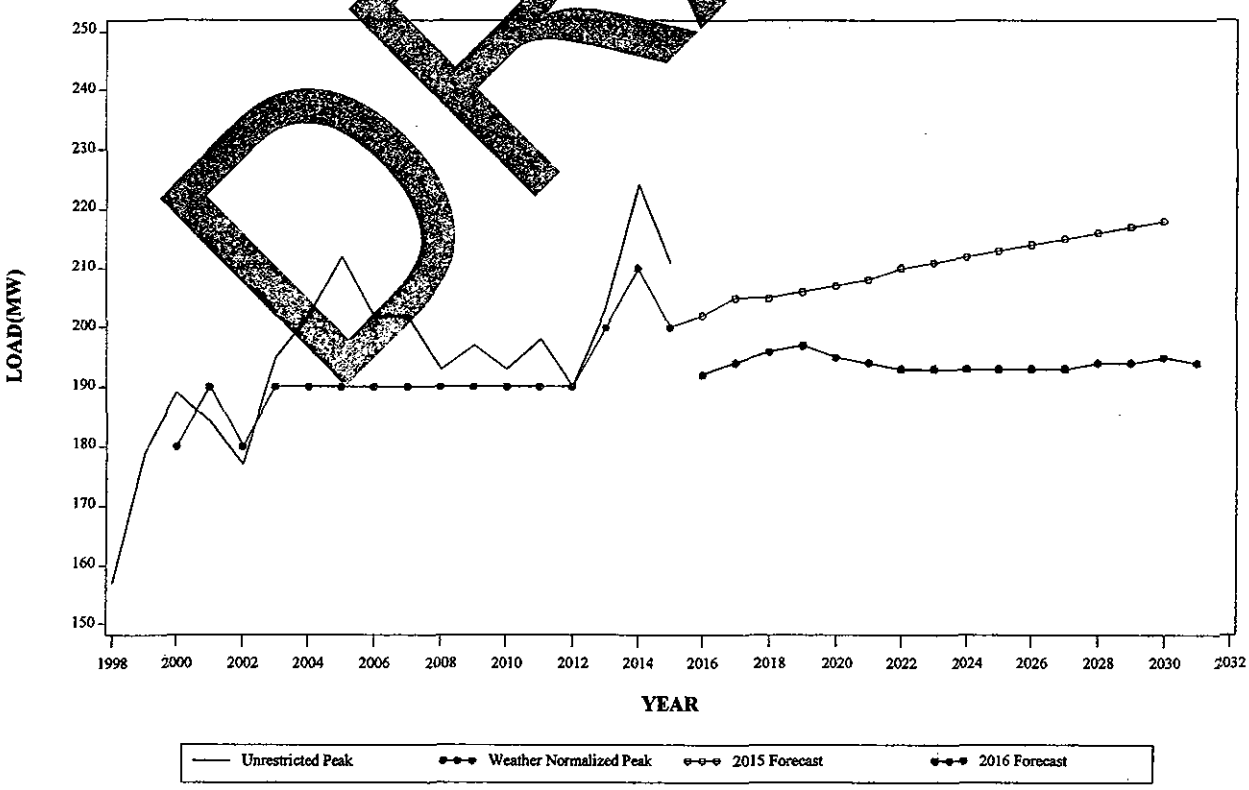

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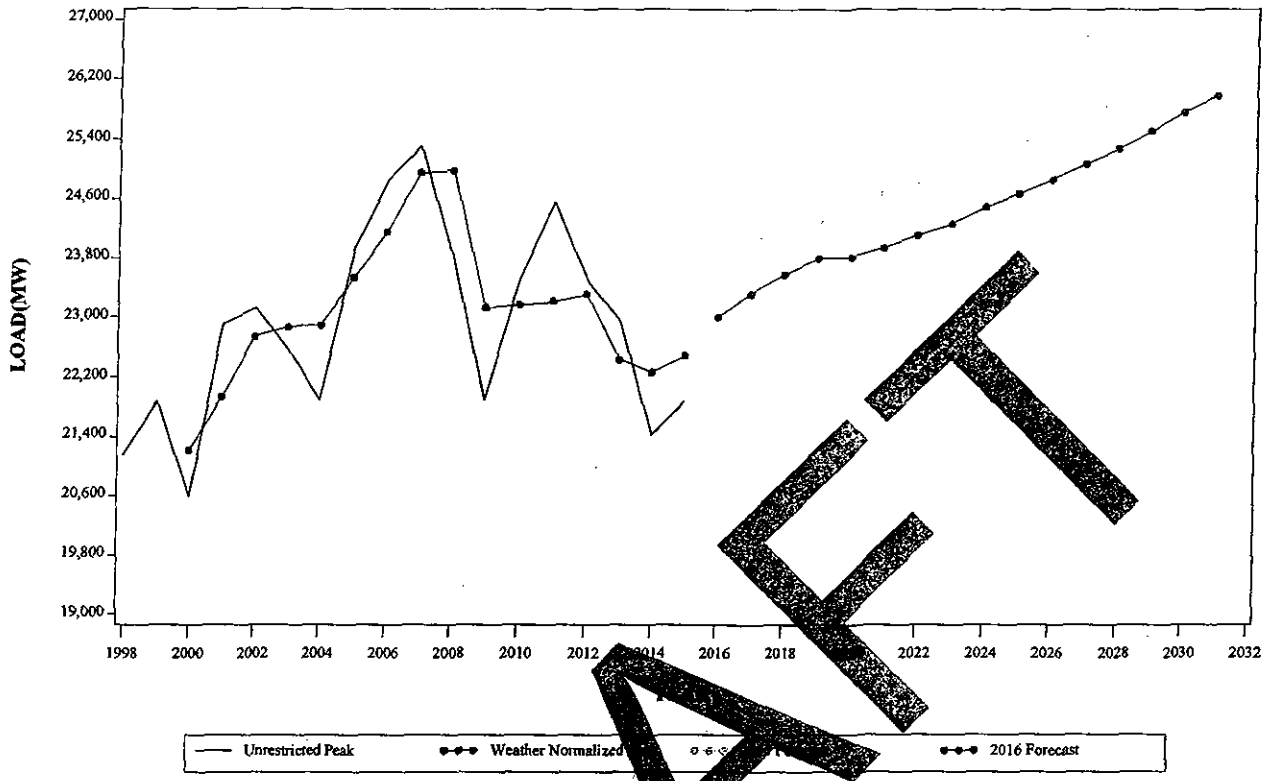

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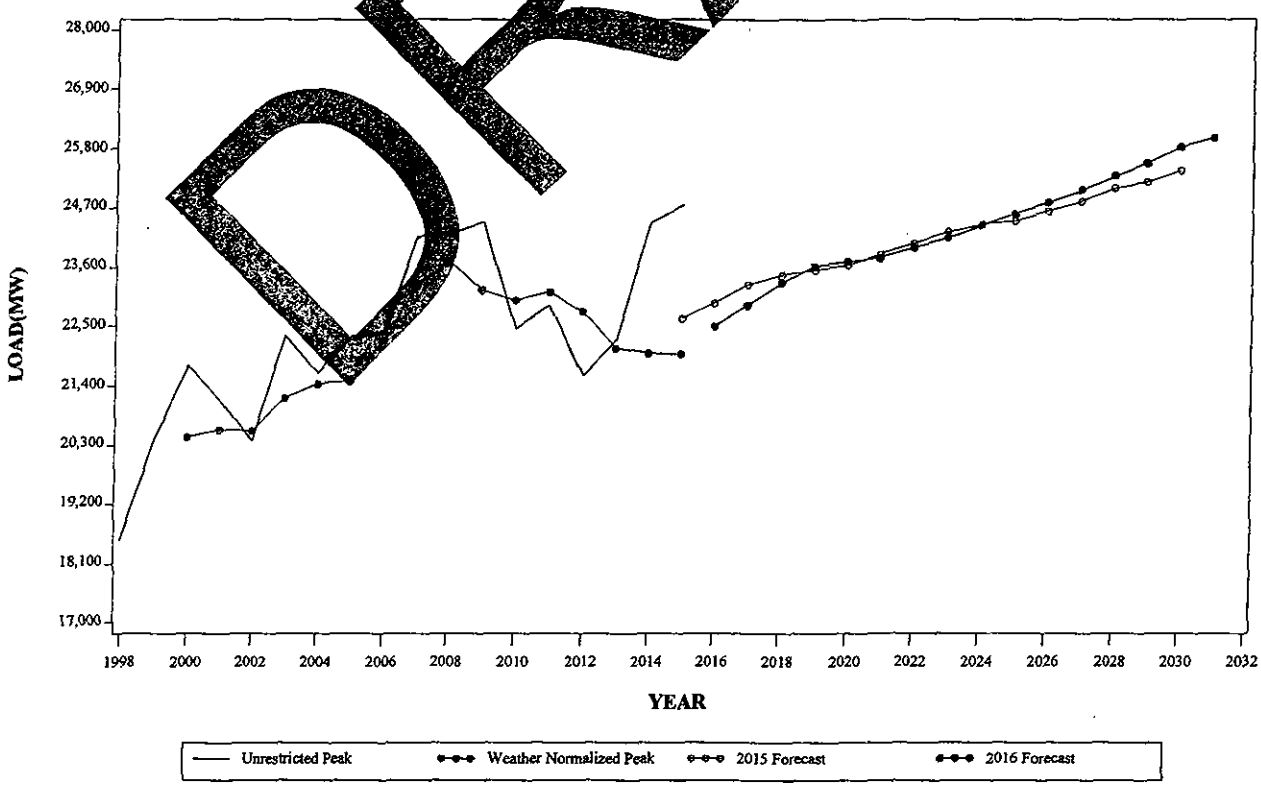

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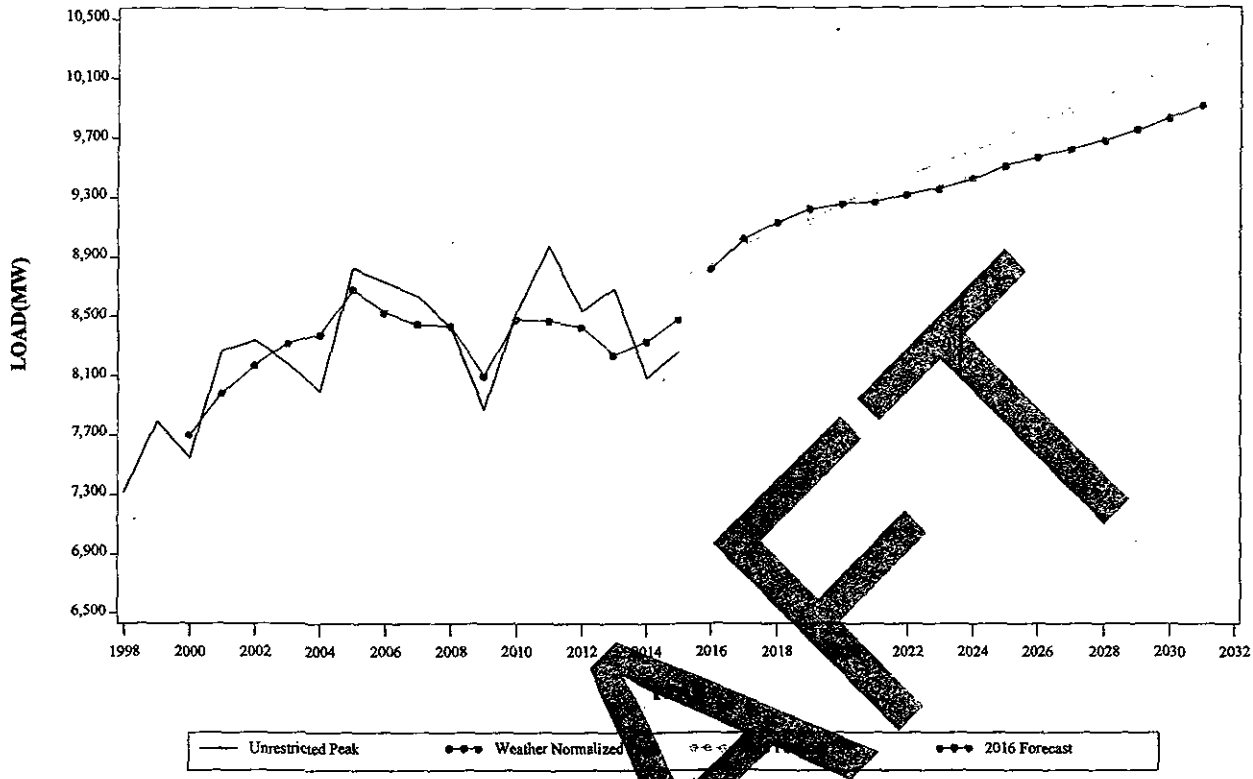

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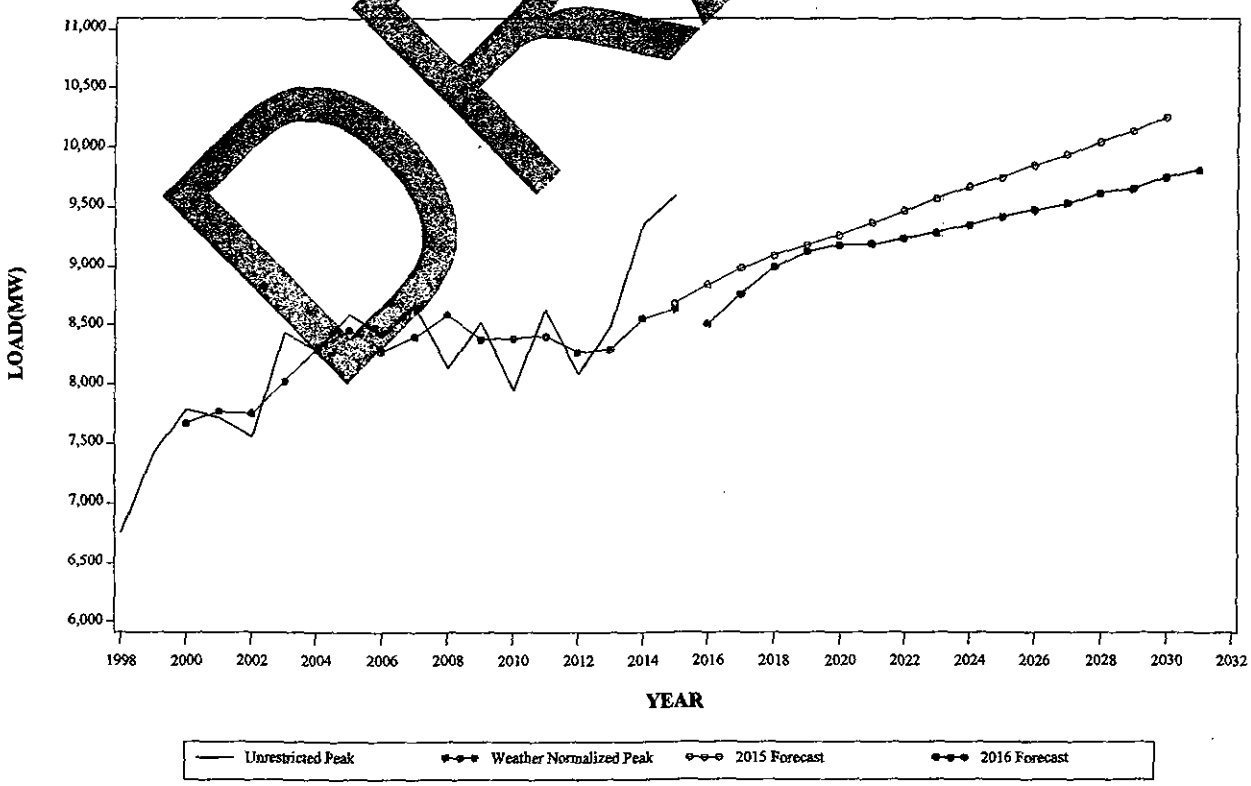

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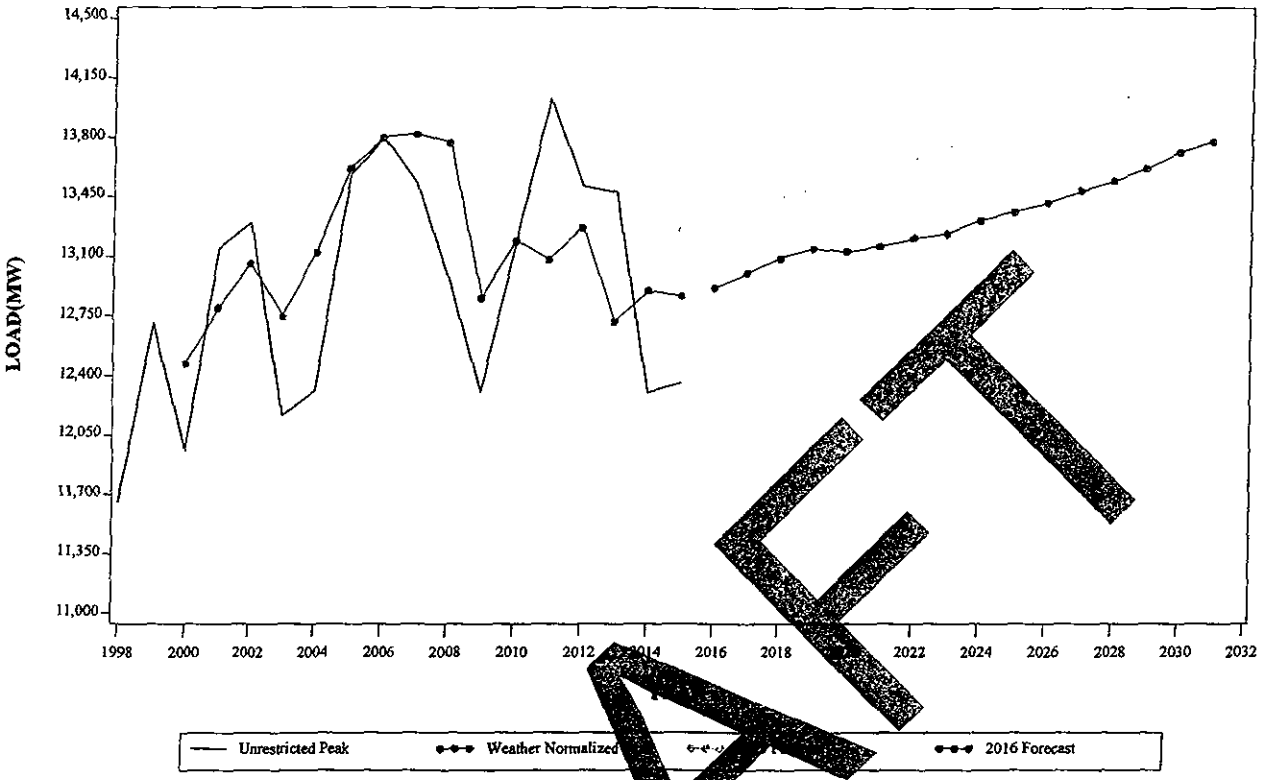
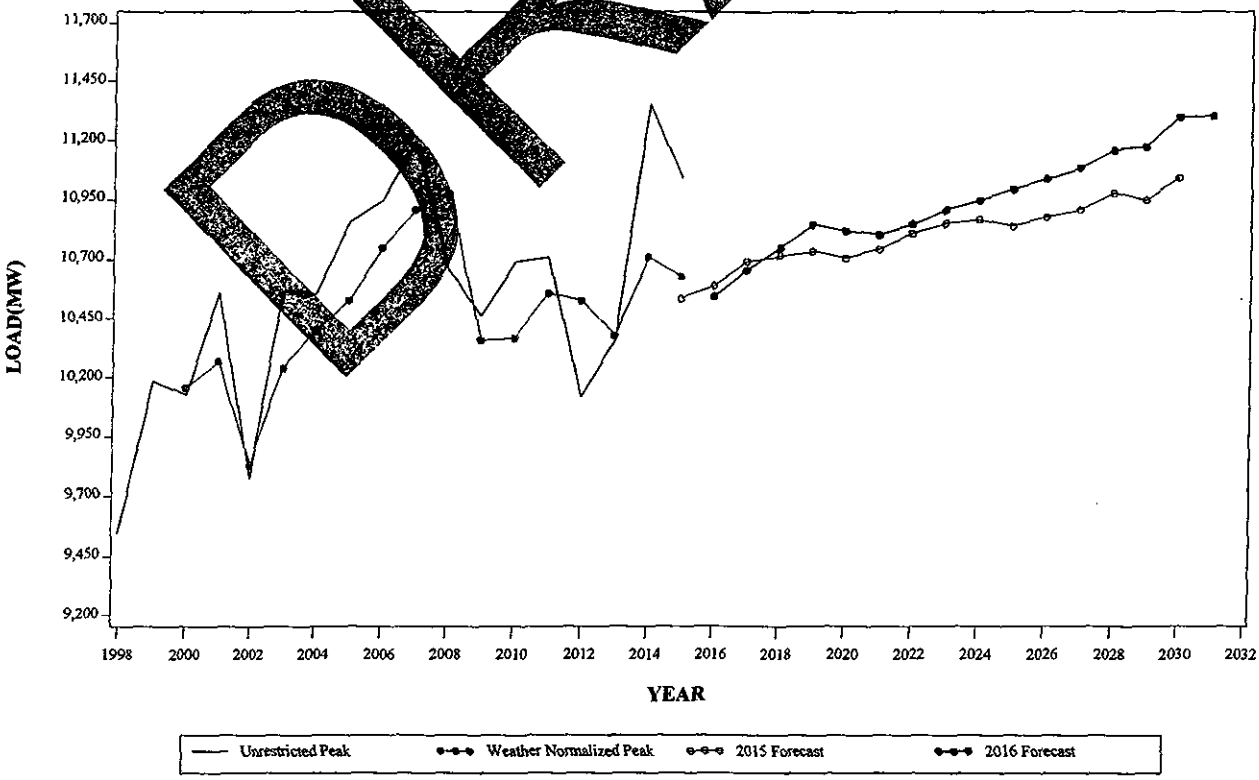
SUMMER PEAK DEMAND FOR ATSI GEOGRAPHIC ZONE



WINTER PEAK DEMAND FOR ATSI GEOGRAPHIC ZONE



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SUMMER PEAK DEMAND FOR COMED
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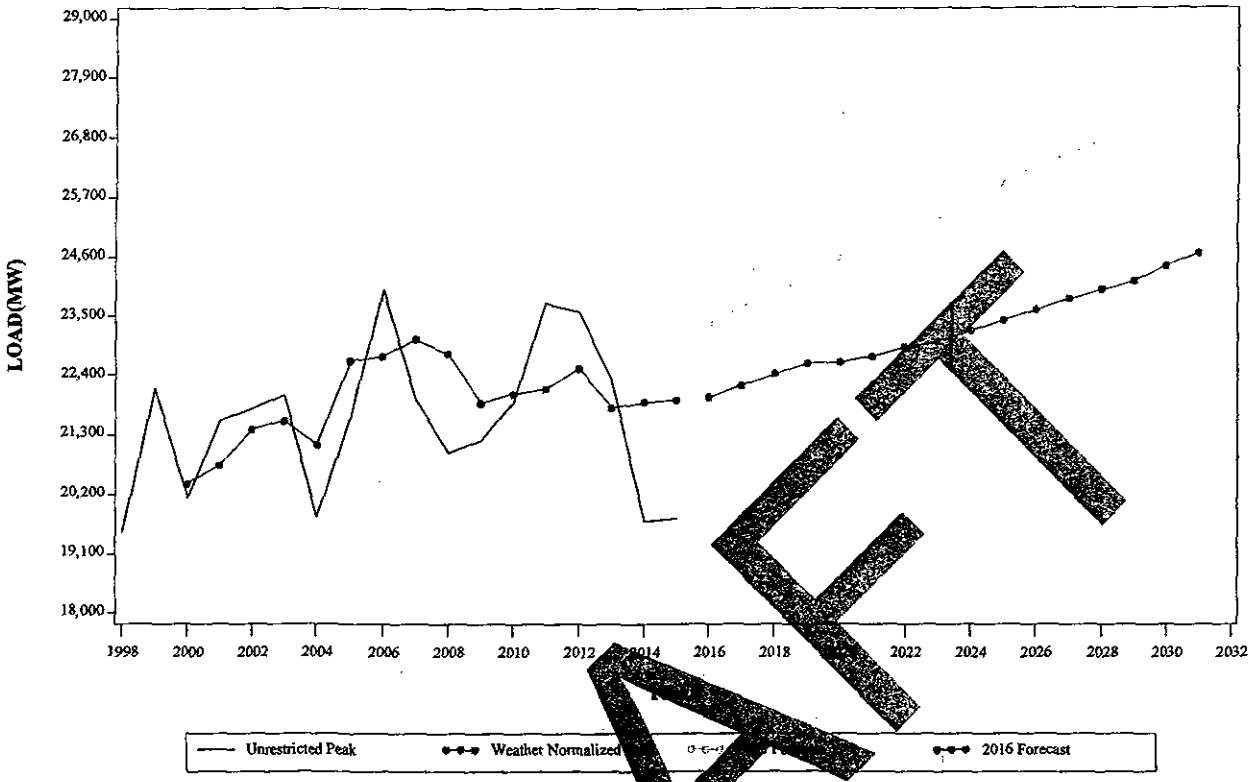

WINTER PEAK DEMAND FOR COMED
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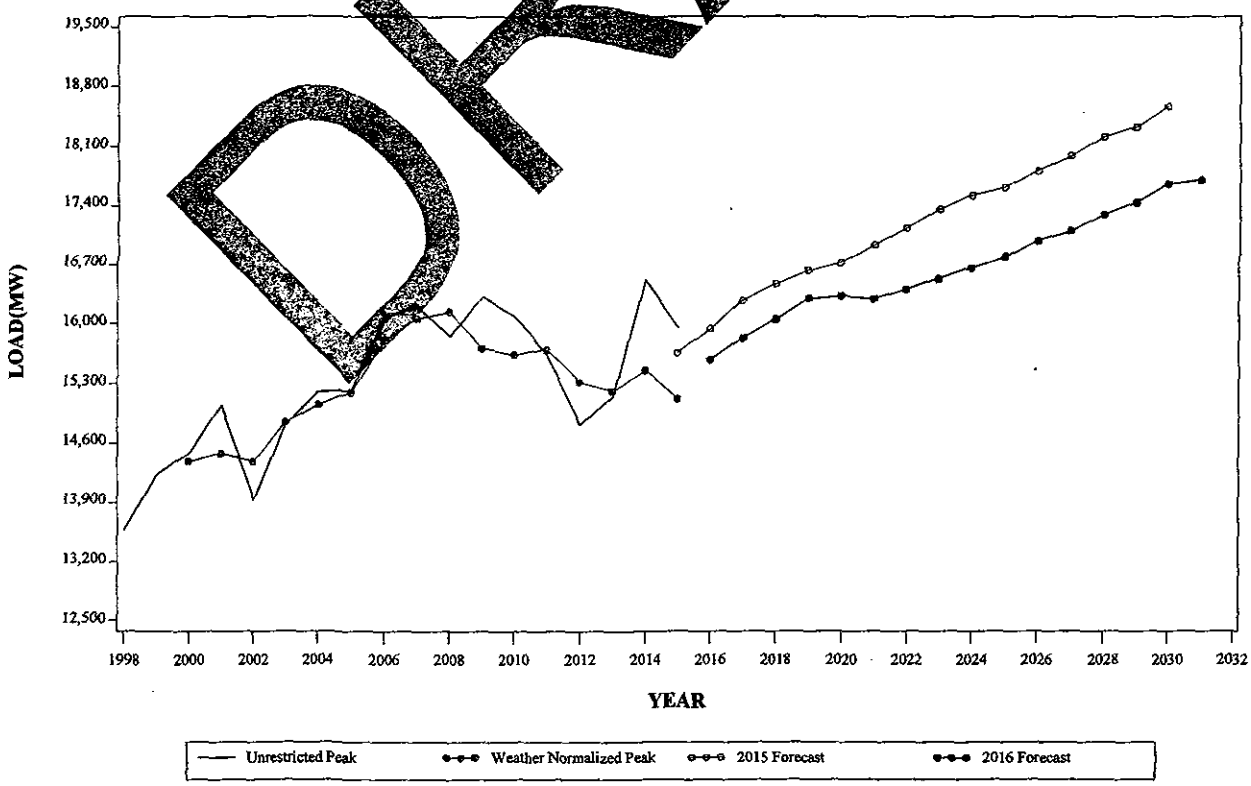

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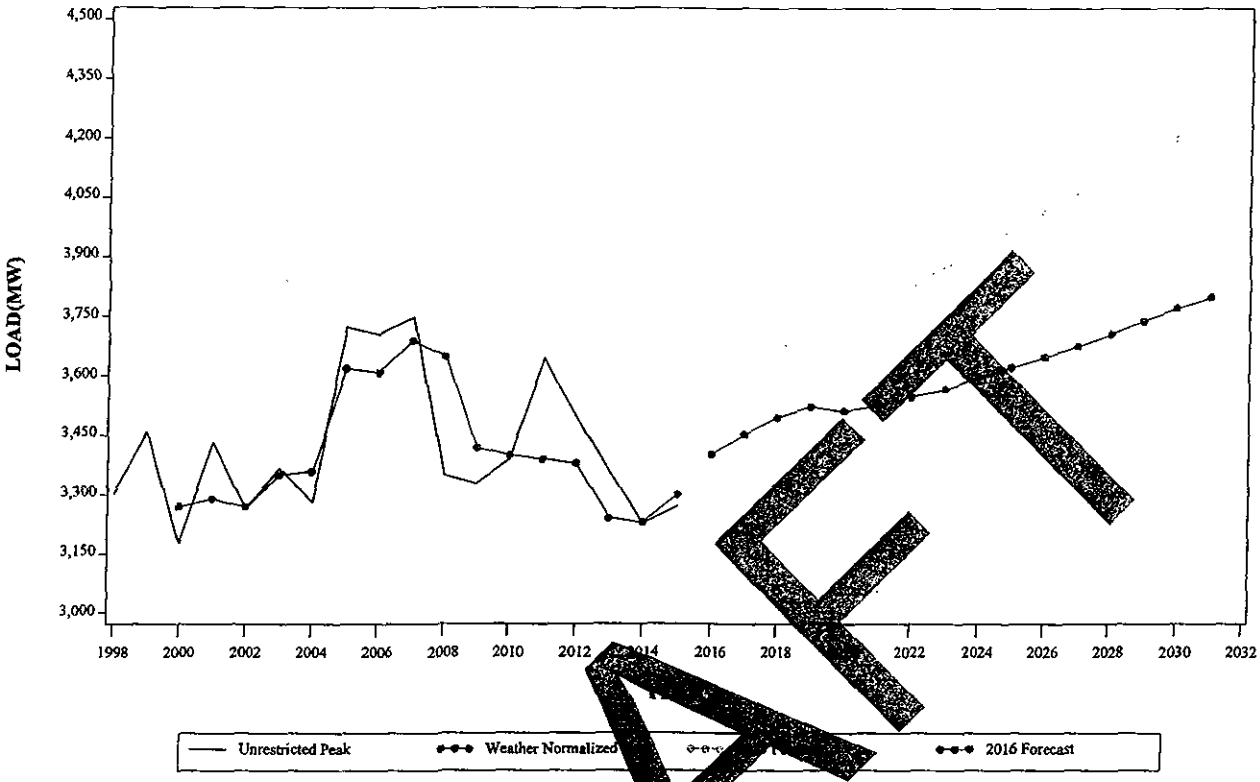
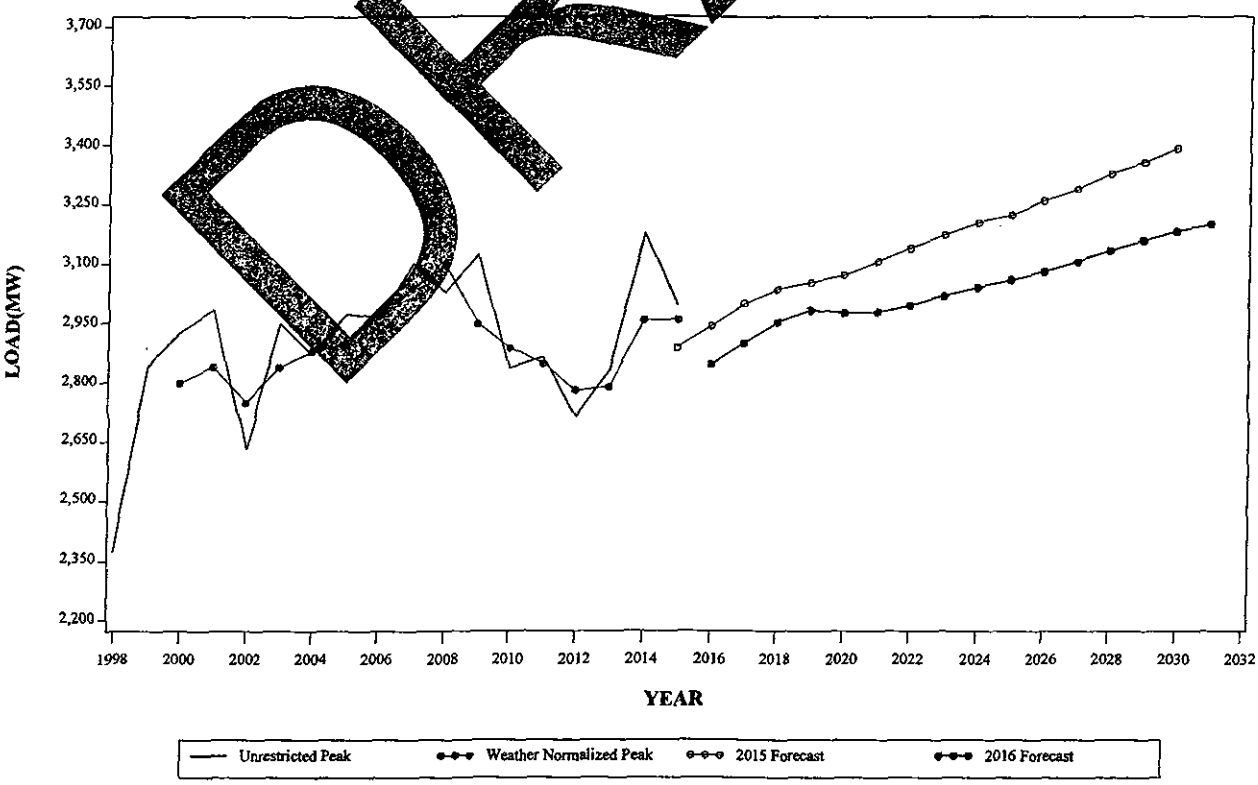
SUMMER PEAK DEMAND FOR DAYTON GEOGRAPHIC ZONE



WIN PEAK DE ND FOR DAYTON GEOGRA C ZONE



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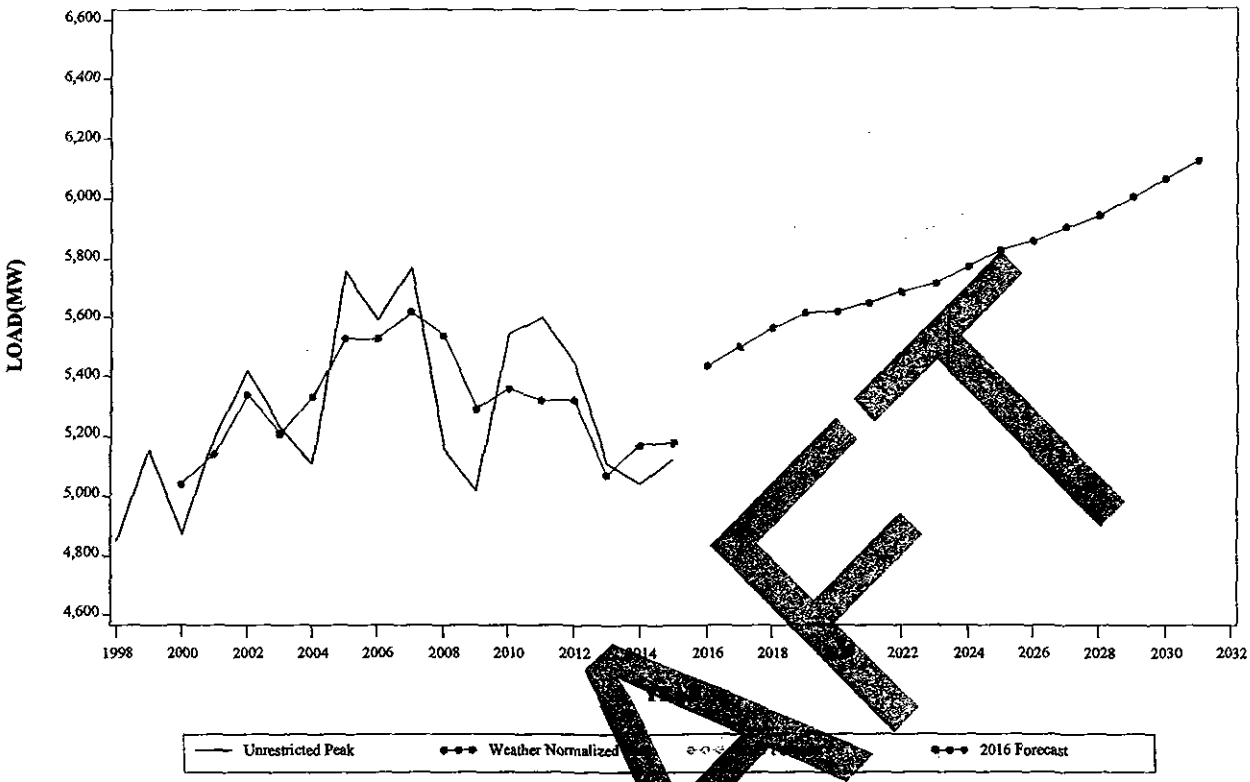
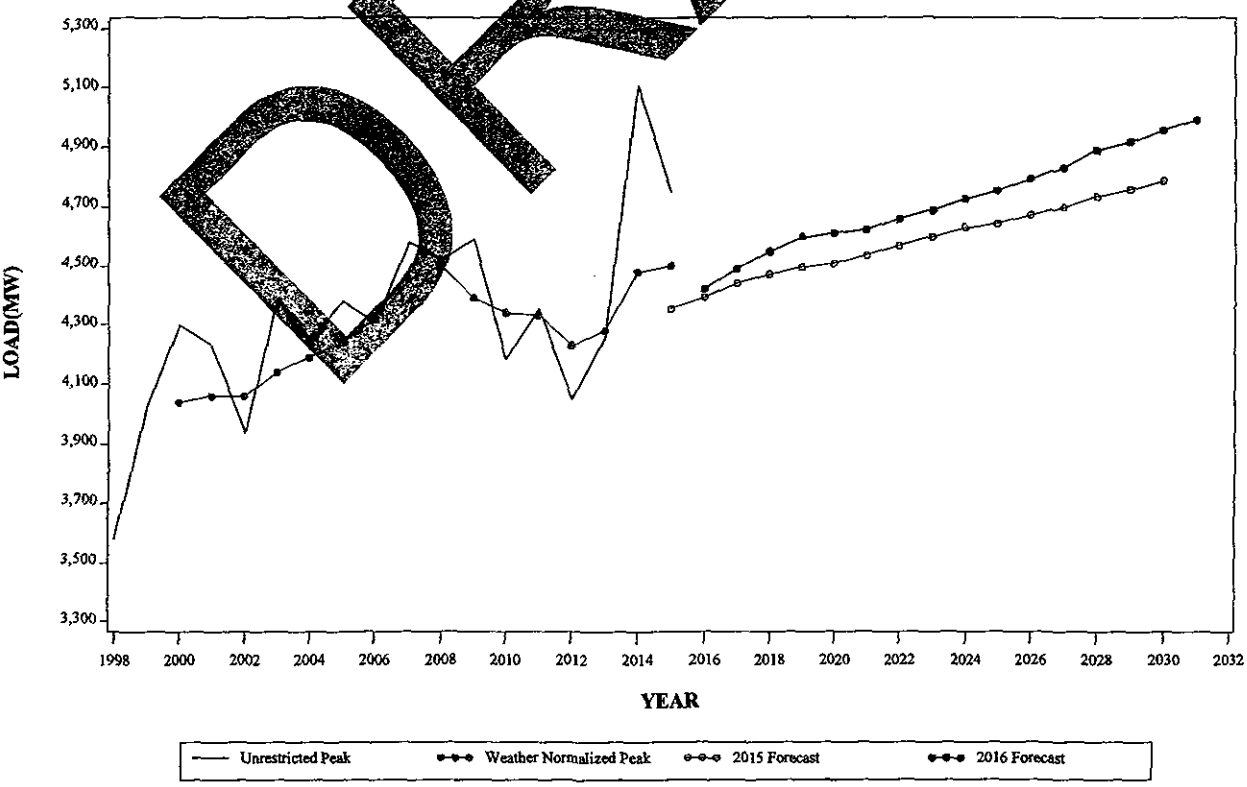
SUMMER PEAK DEMAND FOR DEOK GEOGRAPHIC ZONE



WEATHER PEAK DEMAND FOR DEOK GEOGRAPHIC ZONE



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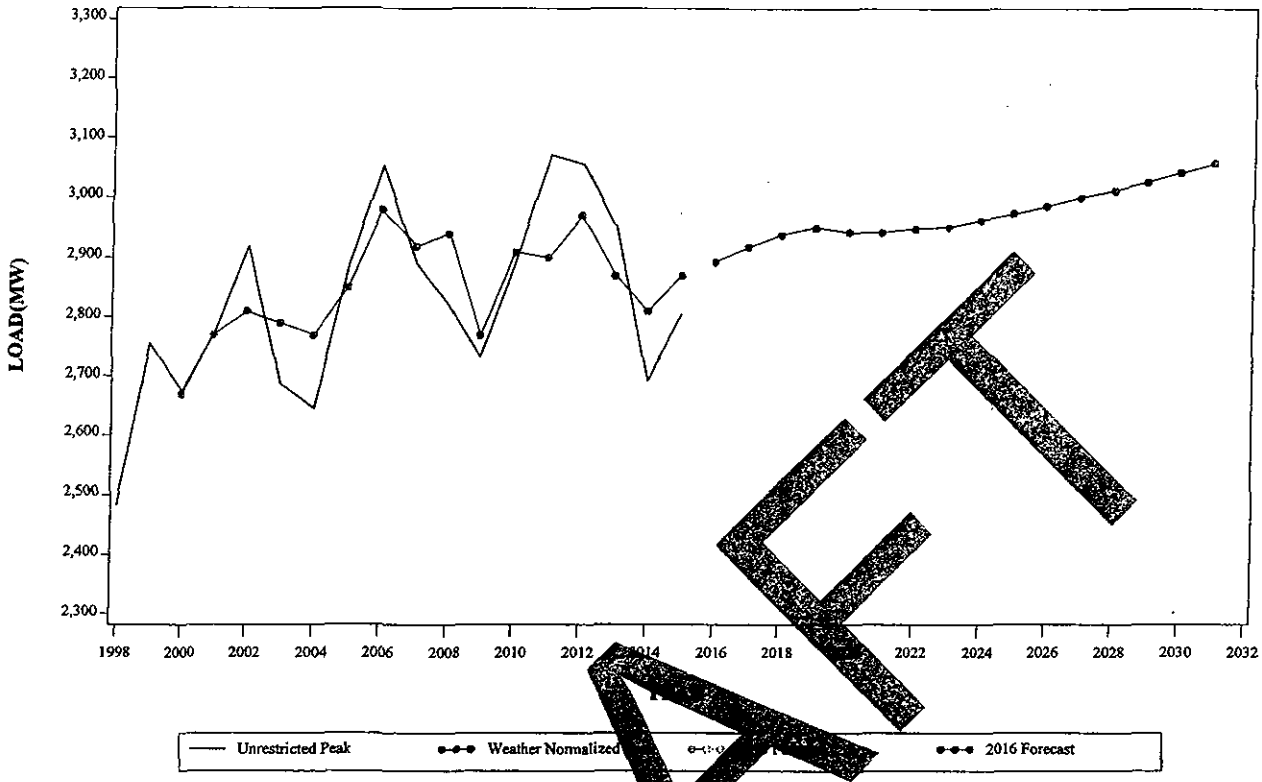
SUMMER PEAK DEMAND FOR DLCO GEOGRAPHIC ZONE



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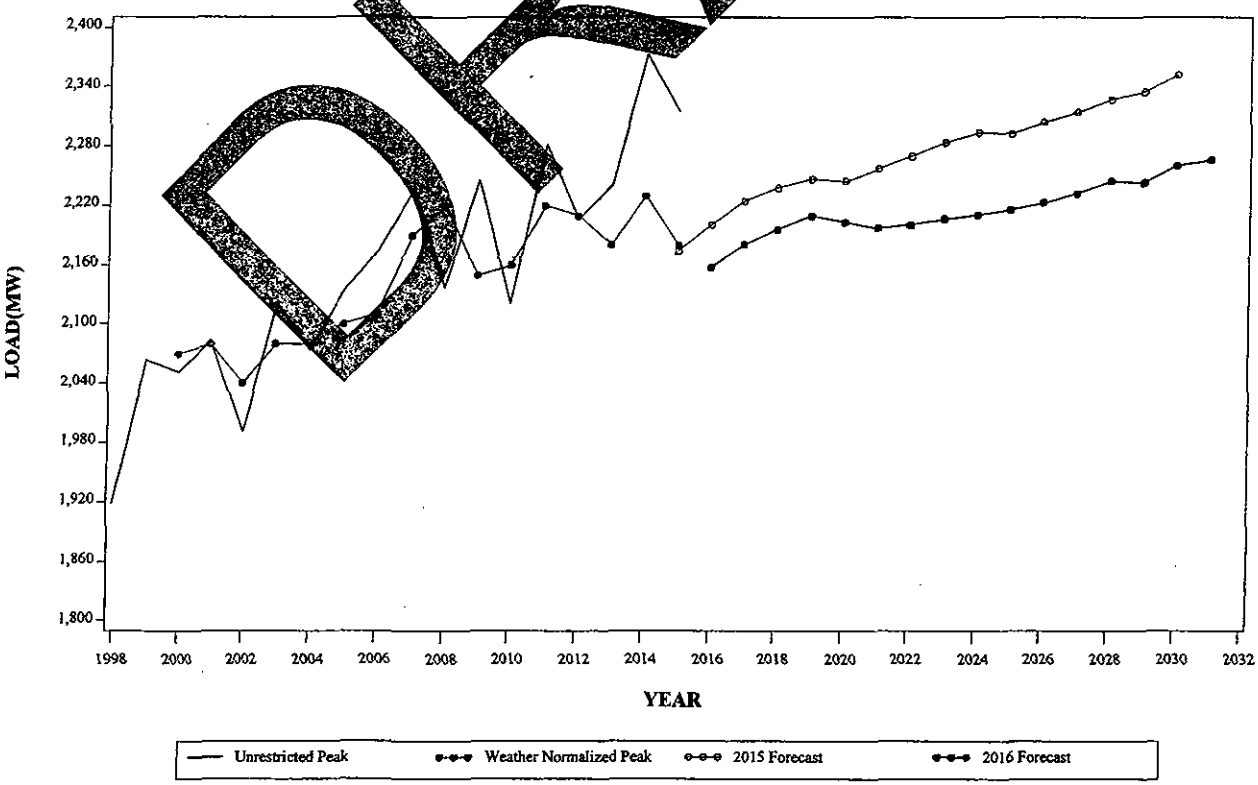

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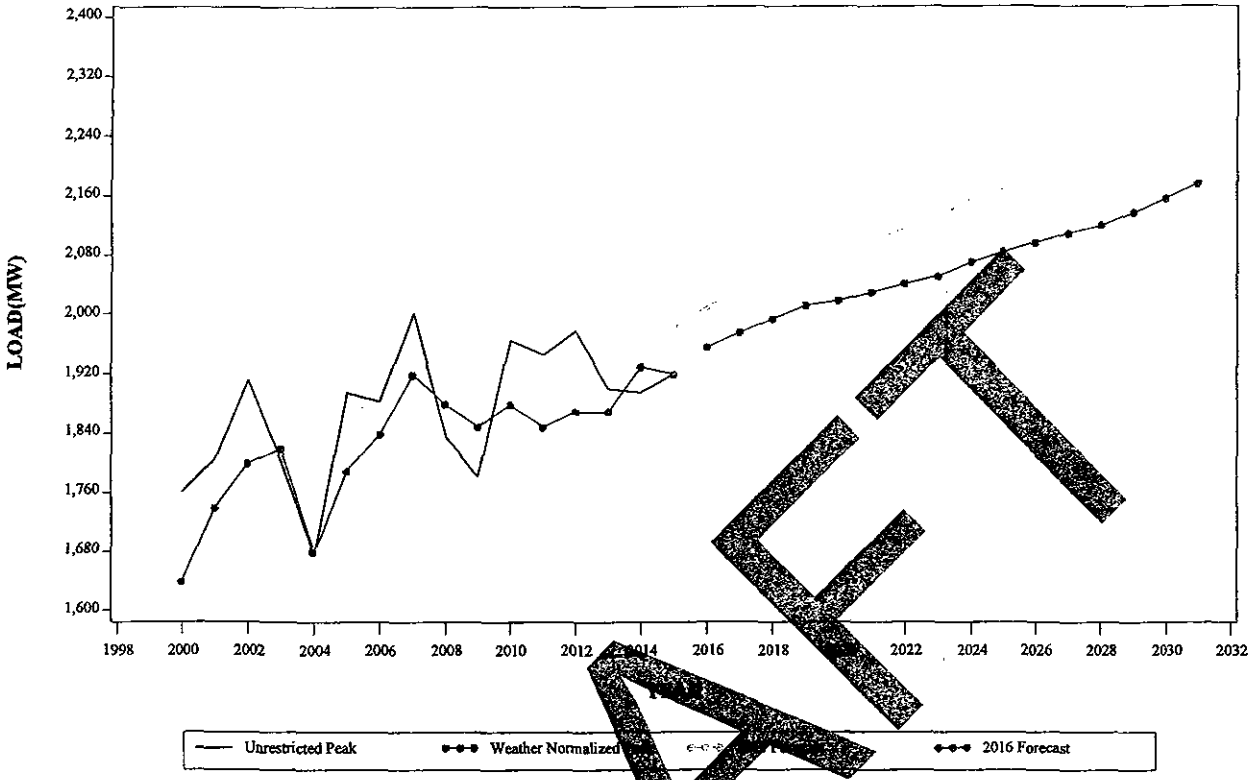
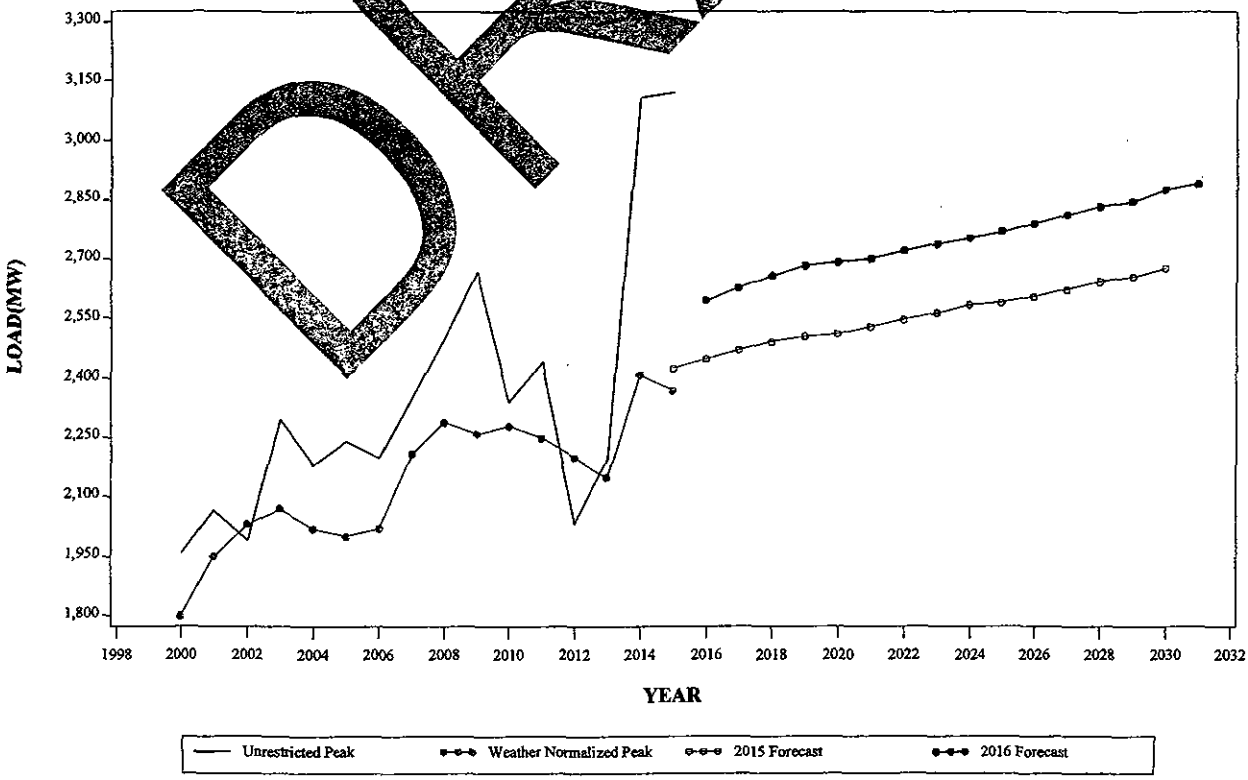
SUMMER PEAK DEMAND FOR EKPC GEOGRAPHIC ZONE



WEATHER PEAK DEMAND FOR EKPC GEOGRAPHIC ZONE



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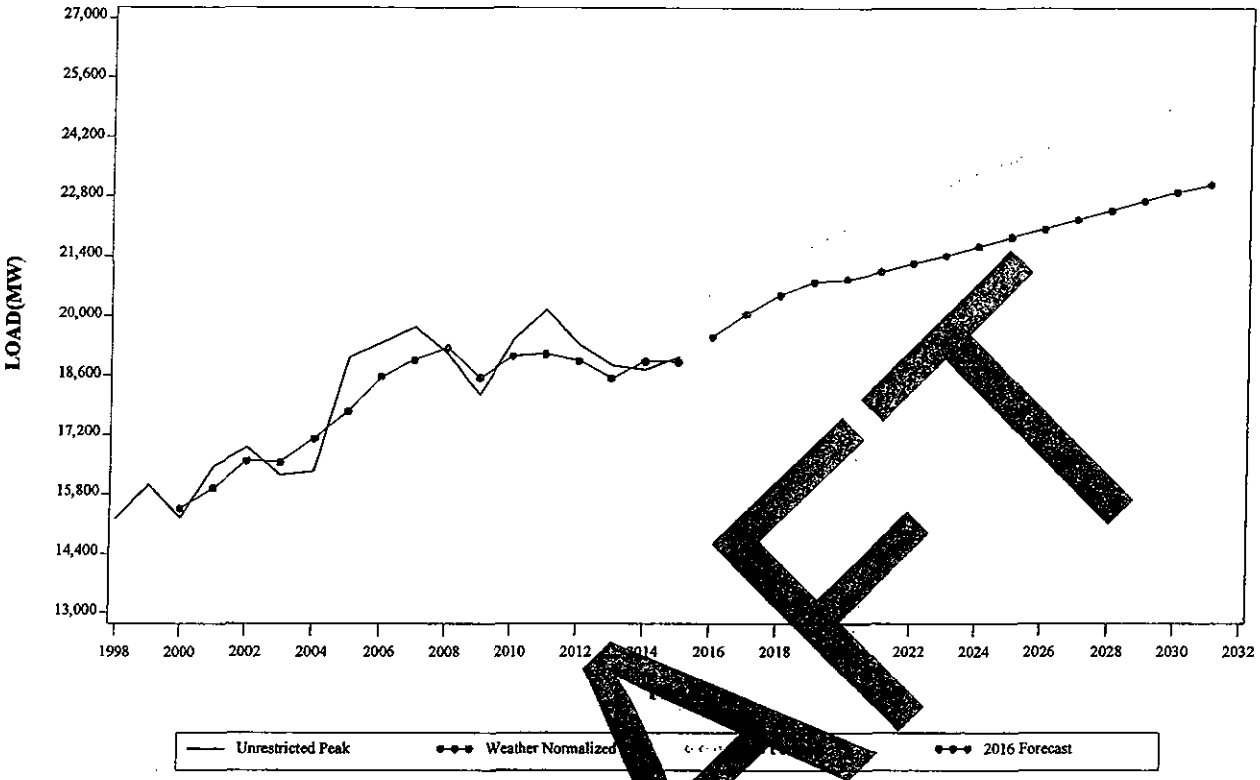
SUMMER PEAK DEMAND FOR DOM GEOGRAPHIC ZONE



WEATHER PEAK DEMAND FOR DOM GEOGRAPHIC ZONE

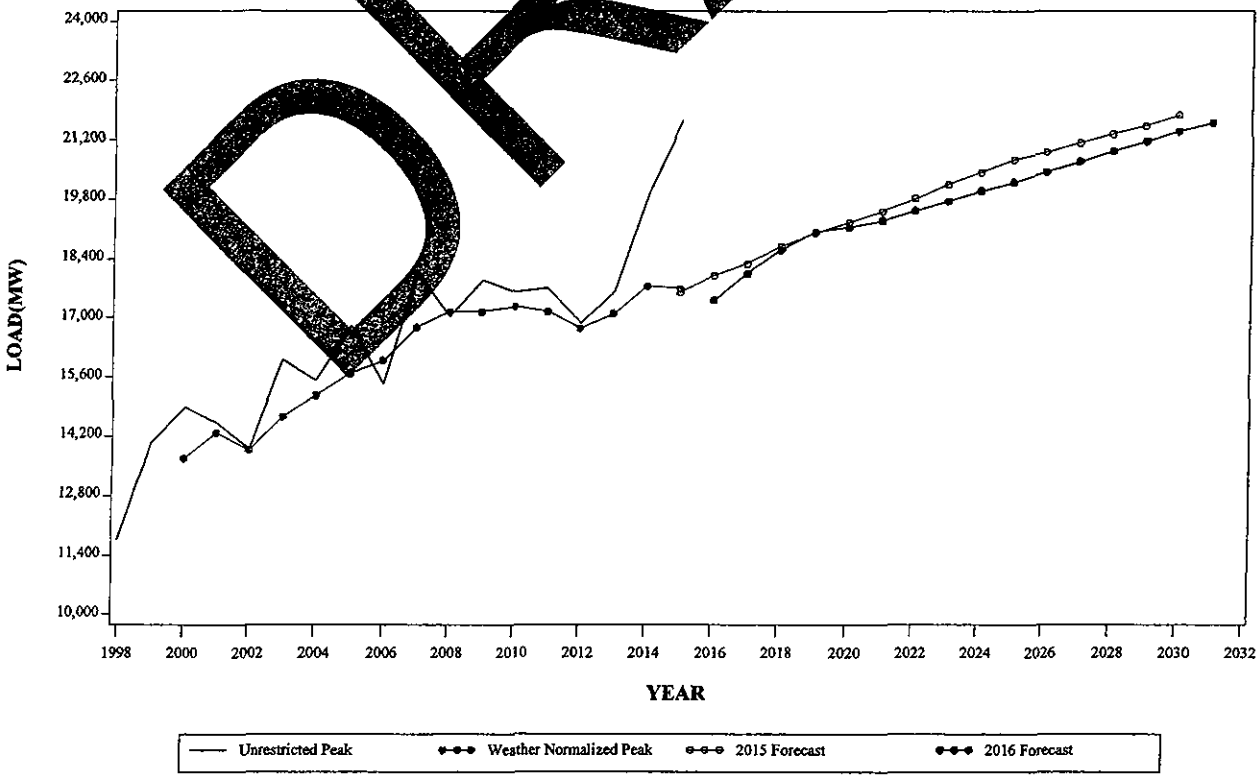


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Table A-1

PJM MID-ATLANTIC REGION
SUMMER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST
TO THE JANUARY 2015 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	2016		2021		2026	
	MW	%	MW	%	MW	%
AE	(178)	-6.6%	(265)	[illegible]6%	(339)	-11.9%
BGE	(267)	-3.7%	(446)	-5.9%	(601)	-7.7%
DPL	(249)	-5.9%	(354)	-8.0%	(460)	-10.0%
JCPL	(395)	-6.2%	(552)	-8.3%	[illegible]58)	-11.0%
METED	(68)	-2.3%	(121)	-3.8%	[illegible]	-5.3%
PECO	(221)	-2.5%	(35[illegible]	-3.9%	(38[illegible]	-4.0%
PENLC	(88)	-3.0%	([illegible]	[illegible]%	(388)	-11.7%
PEPCO	(131)	-2.0%	(2[illegible]	[illegible].0%	(251)	-3.6%
PL	(70)	-1.0%	(162)	-2.1%	(253)	-3.2%
PS	(329)	-3.2%	(506)	-4.7%	(748)	-6.8%
RECO	(21)	-4.9%	(26)	-6.0%	(33)	-7.4%
UGI	(12)	-6.0%	(18)	-8.7%	(24)	-11.2%
PJM MID-ATLANTIC	(2,537)	-4.2%	[illegible]	[illegible]0%	(4,683)	-7.3%
FE-EAST	(630)	-5.2%	([illegible]0)	-7.8%	(1,369)	-10.3%
PLGRP	(96)	[illegible].3%	([illegible]99)	-2.6%	(283)	-3.5%

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Table A-1

PJM WESTERN REGION, PJM SOUTHERN REGION AND PJM RTO
SUMMER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST
TO THE JANUARY 2015 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	2016		2021		2026	
	MW	%	MW	%	MW	%
AEP	(802)	-3.4%	(736)	[illegible]0%	(683)	-2.7%
APS	(56)	-0.6%	(73)	-0.8%	(237)	-2.4%
ATSI	(449)	-3.4%	(477)	-3.5%	(499)	-3.6%
COMED	(1,354)	-5.8%	(2,027)	-8.2%	([illegible]46)	-10.1%
DAYTON	(172)	-4.8%	(260)	-6.9%	[illegible]	-9.1%
DEOK	(140)	-2.5%	(16[illegible]	-[illegible]9%	([illegible]	-3.5%
DLCO	(112)	-3.7%	([illegible]	[illegible]%	(201)	-6.3%
EKPC	(54)	-2.7%	([illegible]	[illegible]3.3%	(94)	-4.3%
PJM WESTERN	(2,977)	-3.6%	(3,778)	-4.4%	(4,567)	-5.1%
DOM	(1,022)	-5.0%	(1,310)	-5.9%	(1,898)	-7.9%
PJM RTO	(5,747)	-3.6%	([illegible]	-[illegible].0%	(10,984)	-6.4%

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Table A-2

PJM MID-ATLANTIC REGION
WINTER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST TO THE JANUARY 2015 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	15/16		20/21		25/26	
	MW	%	MW	%	MW	%
AE	(64)	-3.8%	(111)	[illegible]4%	(140)	-7.9%
BGE	95	1.6%	72	1.2%	40	0.6%
DPL	(12)	-0.4%	(21)	-0.6%	(48)	-1.3%
JCPL	(107)	-2.8%	(193)	-4.8%	([illegible]4)	-7.2%
METED	(32)	-1.2%	(84)	-3.0%	([illegible])	-5.1%
PECO	(6)	-0.1%	(144)	-2.1%	([illegible])	-3.4%
PENLC	(130)	-4.4%	([illegible])	[illegible]%	(480)	-14.5%
PEPCO	18	0.3%	([illegible])	0.7%	(123)	-2.1%
PL	(105)	-1.4%	(193)	-2.5%	(308)	-3.9%
PS	61	0.9%	(18)	-0.3%	(135)	-1.9%
RECO	(2)	-0.9%	(2)	-0.8%	(3)	-1.3%
UGI	(10)	-5.0%	(14)	-6.7%	(21)	-9.8%
PJM MID-ATLANTIC	(351)	-0.8%	([illegible])	[illegible]%	(1,977)	-4.0%
FE-EAST	(291)	-3.1%	([illegible])	-6.2%	(934)	-9.0%
PLGRP	(121)	-1.6%	([illegible]16)	-2.8%	(335)	-4.2%

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Table A-2

PJM WESTERN REGION, PJM SOUTHERN REGION AND PJM RTO
WINTER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST
TO THE JANUARY 2015 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	15/16		20/21		25/26	
	MW	%	MW	%	MW	%
AEP	(427)	-1.9%	(65)	[illegible].3%	167	0.7%
APS	(329)	-3.7%	(176)	-1.9%	(376)	-3.8%
ATSI	(45)	-0.4%	61	0.6%	160	1.5%
COMED	(363)	-2.3%	(633)	-3.7%	[illegible]3)	-4.7%
DAYTON	(98)	-3.3%	(128)	-4.1%	[illegible]	-5.5%
DEOK	28	0.6%	85	[illegible].9%	12[illegible]	2.6%
DLCO	(43)	-2.0%	[illegible]	[illegible]%	(81)	-3.5%
EKPC	148	6.0%	1[illegible]	[illegible].8%	185	7.1%
PJM WESTERN	(1,060)	-1.5%	(775)	-1.1%	(888)	-1.2%
DOM	(589)	-3.3%	(224)	[illegible].1%	(462)	-2.2%
PJM RTO	(1,477)	-1.1%	(1,0[illegible]	[illegible].2%	(2,696)	-1.9%

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Table B-1

SUMMER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION 2016 - 2026

	METERED 2015	UNRESTRICTED 2015	NORMAL 2015	2016	2017	2018	2019	2020	[illegible]	2022	2023	2024	2025	2026	Annual Growth Rate (10 yr)
AE	2,553	2,553	2,580	2,524	2,530	2,534	2,533	2,52[illegible]	[illegible]98	2,506	2,502	2,503	2,506	2,503	(0.1%)
				-2.2%	0.2%	0.2%	-0.0%	-0.[illegible]	[illegible]	-0.1%	-0.2%	0.0%	0.1%	-0.1%	
BGE	6,508	6,508	6,750	6,945	6,989	7,060	7,064	[illegible]	7,0[illegible]	7,060	7,079	7,139	7,192	7,221	0.4%
				2.9%	0.6%	1.0%	0.1%	0.2%	-0.2%	[illegible]1%	0.3%	0.8%	0.7%	0.4%	
DPL	3,822	3,822	3,930	3,991	4,031	4,055	4,0[illegible]	4,072	4,064	[illegible]	4,076	4,092	4,122	4,136	0.4%
				1.6%	1.0%	0.6%	[illegible]	0.1%	-0.2%	[illegible]	0.1%	0.4%	0.7%	0.3%	
JCPL	5,819	5,819	6,010	5,967	6,038	6,096	[illegible]02	6,098	6,091	6,07[illegible]	[illegible],082	6,099	6,132	6,156	0.3%
				-0.7%	1.2%	1.0%	0.1%	-0.1[illegible]	-0.1%	-0.2%	0.1%	0.3%	0.5%	0.4%	
METED	2,791	2,792	2,870	2,939	2,975	3,[illegible]	3,050	[illegible]	3,056	3,068	3,075	3,122	3,147	3,176	0.8%
				2.4%	1.2%	1.5%	1.0%	[illegible]%	0.4%	0.4%	0.2%	1.5%	0.8%	0.9%	
PECO	8,095	8,095	8,390	8,547	8,658	8,745	[illegible]	[illegible]8,810	8,798	8,842	8,885	8,953	9,014	9,123	0.7%
				1.9%	1.3%	1.0%	[illegible]	0.2%	-0.1%	0.5%	0.5%	0.8%	0.7%	1.2%	
PENLC	2,819	2,819	2,940	2,890	2,900	2,904	2,9[illegible]	2,907	2,899	2,901	2,899	2,903	2,908	2,919	0.1%
				-1.7%	[illegible]	0.1%	0.1%	[illegible]0%	-0.3%	0.1%	-0.1%	0.1%	0.2%	0.4%	
PEPCO	6,268	6,268	6,090	6,563	[illegible]	[illegible]	6,668	[illegible]	6,673	6,681	6,694	6,716	6,752	6,814	0.4%
				7.8%	[illegible]%	[illegible]	0.6%	0[illegible]	-0.4%	0.1%	0.2%	0.3%	0.5%	0.9%	
PL	6,580	6,580	6,920	7,192	[illegible]	7,33[illegible]	[illegible]	7,363	7,377	7,406	7,425	7,468	7,518	7,561	0.5%
				3.9%	1.[illegible]	0.[illegible]	0.5%	0.2%	0.2%	0.4%	0.3%	0.6%	0.7%	0.6%	
PS	9,595	9,595	9,910	10,089	10,1[illegible]	[illegible]4	10,238	10,215	10,192	10,188	10,179	10,185	10,208	10,224	0.1%
				[illegible]%	0.8%	[illegible]6%	0.0%	-0.2%	-0.2%	-0.0%	-0.1%	0.1%	0.2%	0.2%	
RECO	398	398	[illegible]	[illegible]7	409	411	411	411	409	409	409	409	410	410	0.1%
				[illegible]	0.5%	[illegible]5%	0.0%	0.0%	-0.5%	0.0%	0.0%	0.0%	0.2%	0.0%	
UGI	189	189	195	[illegible]8	190	[illegible]91	191	190	189	189	189	190	190	190	0.1%
				[illegible]%	1.1%	[illegible]%	0.0%	-0.5%	-0.5%	0.0%	0.0%	0.5%	0.0%	0.0%	
DIVERSITY - MID-ATLANTIC(-)				1,068	1,041	1,023	941	891	1,011	958	878	937	802	880	
PJM MID-ATLANTIC	54,890	54,890	[illegible]	57,174	57,736	58,194	58,464	58,524	58,310	58,439	58,616	58,842	59,297	59,553	0.4%
				1.2%	1.0%	0.8%	0.5%	0.1%	-0.4%	0.2%	0.3%	0.4%	0.8%	0.4%	
FE-EAST	11,267	11,267	[illegible],670	[illegible]8	11,655	11,762	11,810	11,771	11,765	11,795	11,831	11,882	11,929	11,982	0.4%
				[illegible]1%	1.0%	0.9%	0.4%	-0.3%	-0.1%	0.3%	0.3%	0.4%	0.4%	0.4%	
PLGRP	6,759	6,759	[illegible]10	7,336	7,417	7,487	7,525	7,513	7,521	7,548	7,576	7,620	7,666	7,714	0.5%
				3.2%	1.1%	0.9%	0.5%	-0.2%	0.1%	0.4%	0.4%	0.6%	0.6%	0.6%	

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Notes:
Normal 2015 and all forecast values are non-coincident as estimated by PJM staff.
Normal 2015 and all forecast values represent unrestricted peaks, prior to reductions for load management and energy efficiency.
All average growth rates are calculated from the first year of the forecast.

Table B-1 (Continued)

SUMMER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION 2027 - 2031

	2027	2028	2029	2030	2031	Annual Growth Rate (15 yr)
AE	2,497	2,493	2,489	2,484	[illegible]	(0.1%)
	-0.2%	-0.2%	-0.2%	-0.2%	[illegible]	
BGE	7,232	7,239	7,299	7,3[illegible]	7,375	0.4%
	0.2%	0.1%	0.8%	[illegible]3%	0.8%	
DPL	4,140	4,156	4,171	[illegible]181	4,201	[illegible]%
	0.1%	0.4%	0.4[illegible]	0.2%	0.5%	
JCPL	6,181	6,174	6,[illegible]	6,217	6,256	0.[illegible]
	0.4%	-0.1%	[illegible]%	0.1%	0.6%	
METED	3,205	3,213	[illegible]259	3,30[illegible]	[illegible]3,332	0.8%
	0.9%	0.2%	[illegible]	[illegible]	0.9%	
PECO	9,162	9,238	9,[illegible]	[illegible]4	9,488	0.7%
	0.4%	0.8%	0.9[illegible]	[illegible].9%	0.9%	
PENLC	2,92[illegible]	2,920	2,924	[illegible]33	2,942	0.1%
	0[illegible]	[illegible]0%	0.1%	[illegible]	0.3%	
PEPCO	6,8[illegible]	[illegible]	6,847	6,8[illegible]	6,936	0.4%
	-0.0[illegible]	0.3%	[illegible]	0.7%	0.6%	
PL	7,620	7,659	[illegible]	[illegible]769	7,833	0.6%
	0.8%	[illegible]0.5%	0.7%	[illegible]%	0.8%	
PS	10,242	[illegible]	10,253	10,270	10,299	0.1%
	0.2%	[illegible]	0.1%	0.2%	0.3%	
RECO	410	[illegible]0	411	411	412	0.1%
	0.0%	0[illegible]	0.2%	0.0%	0.2%	
UGI	191	1[illegible]	192	193	194	0.2%
	[illegible]5%	0.0[illegible]	0.5%	0.5%	0.5%	
DIVERSITY - MI[illegible]IC(-)	1,007	880	914	957	812	
PJM MID-ATLANTI[illegible]	59,605	59,890	60,176	60,419	60,941	0.4%
	0.1%	0.5%	0.5%	0.4%	0.9%	
FE-EAST	12,036	12,095	12,164	12,216	12,290	0.4%
	0.5%	0.5%	0.6%	0.4%	0.6%	
PLGRP	7,770	7,816	7,876	7,925	7,986	0.6%
	0.7%	0.6%	0.8%	0.6%	0.8%	

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Notes:
Normal 2015 and all forecast values are non-coincident as estimated by PJM staff.
Normal 2015 and all forecast values represent unrestricted peaks, prior to reductions for load management and energy efficiency.
All average growth rates are calculated from the first year of the forecast.

Table B-1

SUMMER PEAK LOAD (MW) AND GROWTH RATES FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2016 - 2026

	METERED 2015	UNRESTRICTED 2015	NORMAL 2015	2016	2017	2018	2019	2020	[illegible]	2022	2023	2024	2025	2026	Annual Growth Rate (10 yr)
AEP	21,877	21,877	22,490	23,010	23,313	23,585	23,795	23,8[illegible]	[illegible]35	24,104	24,260	24,489	24,662	24,856	0.8%
				2.3%	1.3%	1.2%	0.9%	[illegible]	[illegible]	0.7%	0.6%	0.9%	0.7%	0.8%	
APS	8,257	8,257	8,480	8,816	9,016	9,129	9,218	[illegible]52	9,[illegible]	9,314	9,355	9,417	9,501	9,563	0.8%
				4.0%	2.3%	1.3%	1.0%	0.4%	0.2%	[illegible]5%	0.4%	0.7%	0.9%	0.7%	
ATSI	12,357	12,357	12,870	12,920	13,005	13,089	13,[illegible]	13,130	13,159	[illegible]8	13,236	13,312	13,363	13,415	0.4%
				0.4%	0.7%	0.6%	[illegible]	-0.1%	0.2%	[illegible]	0.2%	0.6%	0.4%	0.4%	
COMED	19,766	19,768	21,950	21,998	22,215	22,437	[illegible]629	22,659	22,766	22,9[illegible]	[illegible]3,041	23,242	23,448	23,630	0.7%
				0.2%	1.0%	1.0[illegible]	0.9%	0.[illegible]	0.5%	0.7%	0.5%	0.9%	0.9%	0.8%	
DAYTON	3,269	3,269	3,300	3,403	3,454	3[illegible]	3,524	[illegible]	3,527	3,548	3,568	3,599	3,623	3,648	0.7%
				3.1%	1.5%	1.2[illegible]	0.8%	[illegible]3%	0.4%	0.6%	0.6%	0.9%	0.7%	0.7%	
DEOK	5,123	5,123	5,180	5,436	5,501	5,566	[illegible]	5,622	5,650	5,687	5,715	5,773	5,827	5,856	0.7%
				4.9%	1.2%	1.2%	[illegible]	0.1%	0.5%	0.7%	0.5%	1.0%	0.9%	0.5%	
DLCO	2,805	2,805	2,870	2,893	2,918	2,938	2,9[illegible]	2,943	2,942	2,948	2,951	2,963	2,974	2,986	0.3%
				0.8%	[illegible]	0.7%	0.4%	[illegible]2%	-0.0%	0.2%	0.1%	0.4%	0.4%	0.4%	
EKPC	1,920	1,920	1,920	1,956	[illegible]	[illegible]94	2,012	[illegible]9	2,030	2,042	2,051	2,071	2,085	2,097	0.7%
				1.9%	[illegible]0%	[illegible]	0.9%	[illegible]	0.5%	0.6%	0.4%	1.0%	0.7%	0.6%	
DIVERSITY - WESTERN(-)				1,575	1,[illegible]	[illegible]	1,55[illegible]	1,571	1,588	1,626	1,496	1,548	1,593	1,595	
PJM WESTERN	74,531	74,579	77,98[illegible]	78,857	79,8[illegible]	[illegible]65	81,333	81,382	81,687	82,158	82,681	83,318	83,890	84,456	0.7%
				[illegible]1%	1.2[illegible]	1.1%	0.8%	0.1%	0.4%	0.6%	0.6%	0.8%	0.7%	0.7%	
DOM	18,980	19,024	18,920	1[illegible]9	20,053	[illegible]500	20,812	20,885	21,057	21,247	21,423	21,641	21,860	22,047	1.2%
				[illegible]2%	2.7%	[illegible]2%	1.5%	0.4%	0.8%	0.9%	0.8%	1.0%	1.0%	0.9%	
DIVERSITY - INTERREGIONAL(-)				3,395	[illegible]	3,408	3,613	3,866	3,659	3,824	3,713	3,781	4,074	4,142	
PJM RTO	143,447	143,497	[illegible]	152,165	154,184	155,951	156,996	156,925	157,395	158,020	159,007	160,020	160,973	161,914	0.6%
				1.2%	1.3%	1.1%	0.7%	-0.0%	0.3%	0.4%	0.6%	0.6%	0.6%	0.6%	

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Notes:
Normal 2015 and all forecast values are non-coincident as estimated by PJM staff.
Normal 2015 and all forecast values represent unrestricted peaks, prior to reductions for load management and energy efficiency.
All average growth rates are calculated from the first year of the forecast.

Table B-1 (Continued)

SUMMER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO 2027 - 2031

	2027	2028	2029	2030	203[illegible]	Annual [illegible]wth Rate (15 yr)
AEP	25,071	25,275	25,507	25,766	[illegible]	0.8%
	0.9%	0.8%	0.9%	1.0%	0.8[illegible]	
APS	9,616	9,674	9,743	9,8[illegible]	9,914	0.8%
	0.6%	0.6%	0.7%	0.8%	0.9%	
ATSI	13,489	13,545	13,619	[illegible],712	13,781	[illegible]4%
	0.6%	0.4%	0.5[illegible]	0.7%	0.5%	
COMED	23,836	24,010	24[illegible]	24,450	24,689	0.[illegible]
	0.9%	0.7%	[illegible]%	1.2%	1.0%	
DAYTON	3,676	3,706	[illegible]739	3,77[illegible]	3,799	0.7%
	0.8%	0.8%	[illegible]%	[illegible]	0.7%	
DEOK	5,903	5,944	[illegible]	[illegible]65	6,122	0.8%
	0.8%	0.7%	1.0[illegible]	1.0%	0.9%	
DLCO	3,0[illegible]	3,012	3,026	[illegible]42	3,058	0.4%
	[illegible]	0.4%	0.5%	[illegible]	0.5%	
EKPC	2,[illegible]	[illegible]	2,138	2,1[illegible]	2,176	0.7%
	0.[illegible]	0.5[illegible]	[illegible]%	0.9%	0.9%	
DIVERSITY - WESTERN(-)	1,590	1,48[illegible]	1,421	[illegible]56	1,608	
PJM WESTERN	85,111	[illegible]	86,522	87,229	87,909	0.7%
	0.8%	[illegible]%	0.8%	0.8%	0.8%	
DOM	22,261	22[illegible]	22,699	22,907	23,093	1.1%
	1.0%	0.[illegible]	1.0%	0.9%	0.8%	
DIVERSITY - IN[illegible]GI[illegible]L(-)	3,9[illegible]	[illegible],995	3,986	4,126	4,459	
PJM RTO	163,009	164,166	165,411	166,429	167,484	0.6%
	0.7%	0.7%	0.8%	0.6%	0.6%	

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Notes:
Normal 2015 and all forecast values are non-coincident as estimated by PJM staff.
Normal 2015 and all forecast values represent unrestricted peaks, prior to reductions for load management and energy efficiency.
All average growth rates are calculated from the first year of the forecast.

Table B-2

WINTER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION 2015/16 - 2025/26

	METERED 14/15	UNRESTRICTED 14/15	NORMAL 14/15	15/16	16/17	17/18	18/19	19/20	[illegible]	21/22	22/23	23/24	24/25	25/26	Annual Growth Rate (10 yr)
AE	1,705	1,705	1,610	1,626	1,632	1,640	1,647	1,63[illegible]	[illegible]	1,620	1,621	1,623	1,623	1,625	(0.0%)
				1.0%	0.4%	0.5%	0.4%	-0[illegible]	[illegible]	0.0%	0.1%	0.1%	0.0%	0.1%	
BGE	6,712	6,712	5,760	5,940	5,994	6,044	6,077	[illegible]	6,0[illegible]	6,098	6,119	6,142	6,168	6,199	0.4%
				3.1%	0.9%	0.8%	0.5%	0.0%	-0.0%	[illegible]3%	0.3%	0.4%	0.4%	0.5%	
DPL	4,114	4,114	3,480	3,412	3,462	3,507	3,5[illegible]	3,544	3,548	[illegible]	3,577	3,598	3,623	3,647	0.7%
				-2.0%	1.5%	1.3%	[illegible]	0.2%	0.1%	0[illegible]	0.5%	0.6%	0.7%	0.7%	
JCPL	3,805	3,805	3,730	3,765	3,823	3,881	[illegible]13	3,881	3,853	3,85[illegible]	[illegible],859	3,874	3,886	3,892	0.3%
				0.9%	1.5%	1.5[illegible]	0.8%	-0.8[illegible]	-0.7%	0.1%	0.1%	0.4%	0.3%	0.2%	
METED	2,799	2,799	2,610	2,593	2,638	2,[illegible]	2,710	[illegible]	2,700	2,711	2,731	2,749	2,767	2,784	0.7%
				-0.7%	1.7%	1.6[illegible]	1.2%	[illegible]%	-0.1%	0.4%	0.7%	0.7%	0.7%	0.6%	
PECO	7,034	7,034	6,620	6,652	6,770	6,859	[illegible]	[illegible],890	6,862	6,900	6,930	6,965	6,997	7,030	0.6%
				0.5%	1.8%	1.3%	[illegible]	-0.2%	-0.4%	0.6%	0.4%	0.5%	0.5%	0.5%	
PENLC	3,025	3,025	2,860	2,814	[illegible],829	2,837	2,8[illegible]	2,841	2,829	2,830	2,834	2,835	2,834	2,834	0.1%
				-1.6%	[illegible]	0.3%	0.4%	[illegible]2%	-0.4%	0.0%	0.1%	0.0%	-0.0%	0.0%	
PEPCO	6,066	6,066	5,370	5,385	[illegible]	[illegible]	5,551	[illegible]	5,562	5,586	5,617	5,642	5,668	5,678	0.5%
				0.3%	[illegible]%	[illegible]	[illegible]7%	[illegible]	-0.1%	0.4%	0.6%	0.4%	0.5%	0.2%	
PL	7,845	7,845	7,140	7,209	[illegible]	7,38[illegible]	[illegible]	7,427	7,404	7,418	7,438	7,475	7,511	7,541	0.5%
				1.0%	1.[illegible]	1.[illegible]	0.7[illegible]	0.1%	-0.3%	0.2%	0.3%	0.5%	0.5%	0.4%	
PS	6,697	6,697	6,570	6,711	6,8[illegible]	[illegible]9	6,921	6,890	6,847	6,843	6,856	6,872	6,887	6,904	0.3%
				[illegible]1%	1.3[illegible]	1.0%	0.8%	-0.4%	-0.6%	-0.1%	0.2%	0.2%	0.2%	0.2%	
RECO	232	232	[illegible]0	[illegible]2	234	[illegible]	235	237	235	234	235	235	235	234	234	0.1%
				[illegible]	0.9%	[illegible]4%	0.9%	-0.8%	-0.4%	0.4%	0.0%	0.0%	-0.4%	0.0%	
UGI	211	211	200	[illegible]2	194	[illegible]96	197	195	194	193	193	193	193	193	0.1%
				[illegible]%	-1.0%	[illegible]%	0.5%	-1.0%	-0.5%	-0.5%	0.0%	0.0%	0.0%	0.0%	
DIVERSITY - MID-ATLANTIC(-)				709	625	633	723	794	731	666	663	646	764	741	
PJM MID-ATLANTIC	49,369	49,369	[illegible]	45,822	46,503	47,010	47,257	47,097	46,999	47,185	47,347	47,557	47,627	47,820	0.4%
				0.7%	1.5%	1.1%	0.5%	-0.3%	-0.2%	0.4%	0.3%	0.4%	0.1%	0.4%	
FE-EAST	9,505	9,505	[illegible],140	[illegible]95	9,229	9,335	9,406	9,336	9,305	9,323	9,358	9,403	9,411	9,442	0.4%
				[illegible]5%	1.5%	1.1%	0.8%	-0.7%	-0.3%	0.2%	0.4%	0.5%	0.1%	0.3%	
PLGRP	8,055	8,055	[illegible]35	7,387	7,476	7,566	7,610	7,584	7,578	7,595	7,614	7,653	7,680	7,711	0.4%
				0.7%	1.2%	1.2%	0.6%	-0.3%	-0.1%	0.2%	0.3%	0.5%	0.4%	0.4%	

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Notes:
Normal 14/15 and all forecast values are non-coincident as estimated by PJM staff.
Normal 14/15 and all forecast values represent unrestricted peaks, prior to reductions for load management and energy efficiency.
All average growth rates are calculated from the first year of the forecast.

Table B-2 (Continued)

WINTER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION 2026/27 - 2030/31

	26/27	27/28	28/29	29/30	30/31	Annual Growth Rate (15 yr)
AE	1,627	1,636	1,638	1,648	[illegible]	0.1%
	0.1%	0.6%	0.1%	0.6%	[illegible]	
BGE	6,227	6,262	6,291	[illegible]	6,346	0.4%
	0.5%	0.6%	0.5%	[illegible]	0.5%	
DPL	3,669	3,694	3,717	[illegible]	3,767	[illegible]
	0.6%	0.7%	[illegible]	0.7%	0.6%	
JCPL	3,914	3,945	[illegible]	3,995	4,006	[illegible]
	0.6%	0.8%	[illegible]	0.7%	0.3%	
METED	2,807	2,831	[illegible]	[illegible]	2,898	0.7%
	0.8%	0.9%	[illegible]	[illegible]	0.6%	
PECO	7,077	7,131	[illegible]	[illegible]	7,263	0.6%
	0.7%	0.8%	[illegible]	[illegible]	0.6%	
PENLC	2,836	2,842	2,840	[illegible]	2,847	0.1%
	[illegible]	[illegible]	-0.1%	[illegible]	-0.2%	
PEPCO	[illegible]	[illegible]	5,778	[illegible]	5,865	0.6%
	[illegible]	1.0%	[illegible]	1.0%	0.5%	
PL	7,582	7,626	[illegible]	[illegible]	7,745	0.5%
	0.5%	0.6%	0.5%	[illegible]	0.5%	
PS	6,922	[illegible]	6,980	7,029	7,036	0.3%
	0.3%	[illegible]	0.3%	0.7%	0.1%	
RECO	235	[illegible]	236	238	236	0.1%
	0.4%	[illegible]	-0.4%	0.8%	-0.8%	
UGI	193	[illegible]	194	195	194	0.1%
	[illegible]	0.5%	0.0%	0.5%	-0.5%	
DIVERSITY - MID-ATLANTIC(-)	725	723	657	704	750	
PJM MID-ATLANTIC	48,074	48,399	48,681	48,954	49,097	0.5%
	0.5%	0.7%	0.6%	0.6%	0.3%	
FE-EAST	9,485	9,544	9,603	9,669	9,684	0.4%
	0.5%	0.6%	0.6%	0.7%	0.2%	
PLGRP	7,752	7,796	7,840	7,873	7,919	0.5%
	0.5%	0.6%	0.6%	0.4%	0.6%	

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Notes:
Normal 25/26 and all forecast values are non-coincident as estimated by PJM staff.
Normal 25/26 and all forecast values represent unrestricted peaks, prior to reductions for load management and energy efficiency.
All average growth rates are calculated from the first year of the forecast.

Table B-2

WINTER PEAK LOAD (MW) AND GROWTH RATES FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2015/16 - 2025/26

	METERED 14/15	UNRESTRICTED 14/15	NORMAL 14/15	15/16	16/17	17/18	18/19	19/20	[illegible]	21/22	22/23	23/24	24/25	25/26	Annual Growth Rate (10 yr)
AEP	24,739	24,739	21,990	22,511	22,899	23,307	23,619	23,7[illegible]	[illegible]74	23,960	24,139	24,367	24,575	24,795	1.0%
				2.4%	1.7%	1.8%	1.3%	[illegible]	[illegible]	0.8%	0.7%	0.9%	0.9%	0.9%	
APS	9,594	9,594	8,640	8,508	8,760	8,990	9,125	[illegible]78	9,[illegible]	9,233	9,281	9,346	9,415	9,471	1.1%
				-1.5%	3.0%	2.6%	1.5%	0.6%	0.1%	[illegible]0.5%	0.5%	0.7%	0.7%	0.6%	
ATSI	11,041	11,041	10,630	10,547	10,658	10,748	10,[illegible]	10,822	10,806	[illegible]9	10,908	10,950	10,995	11,039	0.5%
				-0.8%	1.1%	0.8%	[illegible]	-0.2%	-0.1%	[illegible]	0.5%	0.4%	0.4%	0.4%	
COMED	15,951	15,951	15,120	15,578	15,835	16,055	[illegible],294	16,325	16,297	16,40[illegible]	[illegible]6,531	16,670	16,786	16,976	0.9%
				3.0%	1.6%	1.4[illegible]	1.5%	0.[illegible]	-0.2%	0.7%	0.8%	0.8%	0.7%	1.1%	
DAYTON	2,999	2,999	2,960	2,848	2,901	2[illegible]	2,986	[illegible]	2,980	2,997	3,021	3,044	3,063	3,083	0.8%
				-3.8%	1.9%	1.9[illegible]	1.0%	[illegible]3%	0.1%	0.6%	0.8%	0.8%	0.6%	0.7%	
DEOK	4,750	4,750	4,500	4,421	4,490	4,549	[illegible]	4,609	4,620	4,658	4,688	4,724	4,754	4,793	0.8%
				-1.8%	1.6%	1.3%	[illegible]	0.3%	0.2%	0.8%	0.6%	0.8%	0.6%	0.8%	
DLCO	2,315	2,315	2,180	2,158	2,181	2,196	2,[illegible]	2,204	2,198	2,201	2,207	2,211	2,216	2,223	0.3%
				-1.0%	[illegible]	0.7%	0.6%	[illegible]0.3%	-0.3%	0.1%	0.3%	0.2%	0.2%	0.3%	
EKPC	3,123	3,123	2,370	2,596	[illegible]62	[illegible]57	2,684	[illegible]02	2,702	2,722	2,739	2,755	2,771	2,791	0.7%
				9.5%	[illegible]2%	[illegible]	1.0%	[illegible]	0.4%	0.7%	0.6%	0.6%	0.6%	0.7%	
DIVERSITY - WESTERN(-)				1,347	1,[illegible]	[illegible]	1,628	1,770	1,595	1,491	1,550	1,536	1,531	1,657	
PJM WESTERN	71,834	71,834	66,9[illegible]	67,820	68,9[illegible]	[illegible]040	70,733	70,743	70,968	71,532	71,964	72,531	73,044	73,514	0.8%
				[illegible]3%	1.7[illegible]	1.5%	1.0%	0.0%	0.3%	0.8%	0.6%	0.8%	0.7%	0.6%	
DOM	21,651	21,651	17,690	1[illegible]8	18,064	[illegible]624	19,043	19,164	19,322	19,549	19,776	20,013	20,213	20,461	1.6%
				[illegible]5%	3.6%	[illegible]1%	2.2%	0.6%	0.8%	1.2%	1.2%	1.2%	1.0%	1.2%	
DIVERSITY - INTERREGIONAL(-)				[illegible]	[illegible]	1,028	944	987	888	1,013	1,085	935	932	881	
PJM RTO	142,762	142,762	[illegible]	130,244	132,485	134,646	136,089	136,017	136,401	137,253	138,002	139,166	139,952	140,914	0.8%
				1.5%	1.7%	1.6%	1.1%	-0.1%	0.3%	0.6%	0.5%	0.8%	0.6%	0.7%	

Notes:
Normal 14/15 and all forecast values are non-coincident as estimated by PJM staff.
Normal 14/15 and all forecast values represent unrestricted peaks, prior to reductions for load management and energy efficiency.
All average growth rates are calculated from the first year of the forecast.

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Table B-2 (Continued)

WINTER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO 2026/27 - 2030/31

	26/27	27/28	28/29	29/30	30/31	Annual Growth Rate (15 yr)
AEP	25,025	25,296	25,530	25,837	[illegible]	1.0%
	0.9%	1.1%	0.9%	1.2%	0.7%	
APS	9,524	9,612	9,653	9,7[illegible]	9,804	0.9%
	0.6%	0.9%	0.4%	1.0%	0.6%	
ATSI	11,084	11,158	11,174	[illegible],299	11,302	[illegible]5%
	0.4%	0.7%	0.1[illegible]	1.1%	0.0%	
COMED	17,104	17,294	17[illegible]	17,660	17,697	0.[illegible]
	0.8%	1.1%	[illegible]%	1.2%	0.2%	
DAYTON	3,108	3,136	[illegible]160	3,18[illegible]	3,202	0.8%
	0.8%	0.9%	[illegible]%	[illegible]	0.5%	
DEOK	4,832	4,888	[illegible]	[illegible]58	4,992	0.8%
	0.8%	1.2%	0.6[illegible]	0.8%	0.7%	
DLCO	2,2[illegible]	2,245	2,243	[illegible]260	2,266	0.3%
	[illegible]	0.6%	-0.1%	[illegible]	0.3%	
EKPC	2,[illegible]	[illegible]	2,848	2,8[illegible]	2,892	0.7%
	0.[illegible]	0.7[illegible]	[illegible]%	1.1%	0.5%	
DIVERSITY - WESTERN(-)	1,604	1,64[illegible]	1,571	[illegible]90	1,649	
PJM WESTERN	74,119	[illegible]	75,397	76,032	76,512	0.8%
	0.8%	[illegible]%	0.8%	0.8%	0.6%	
DOM	20,700	20[illegible]	21,183	21,412	21,610	1.4%
	1.2%	1.[illegible]	1.1%	1.1%	0.9%	
DIVERSITY - INT[illegible]EGI[illegible]L(-)	917	[illegible],040	1,361	1,114	1,009	
PJM RTO	141,976	143,127	143,900	145,284	146,210	0.8%
	0.8%	0.8%	0.5%	1.0%	0.6%	

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Notes:
Normal 25/26 and all forecast values are non-coincident as estimated by PJM staff.
Normal 25/26 and all forecast values represent unrestricted peaks, prior to reductions for load management and energy efficiency.
All average growth rates are calculated from the first year of the forecast.

Table B-3

SPRING (APRIL) PEAK LOAD (MW) FOR
EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2016 - 2031

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
AE	1,336	1,336	1,343	1,360	1,352	1,355	1,328	1,318	1,345	[illegible]	1,343	1,339	1,303	1,308	1,310	1,300
BGE	4,719	4,757	4,818	4,857	4,893	4,937	4,845	4,852	4,950	[illegible]	5,038	5,079	4,966	5,034	5,057	5,080
DPL	2,688	2,707	2,785	2,808	2,857	2,871	2,785	2,761	2,853	[illegible]	2,952	2,944	2,828	2,906	2,918	2,947
JCPL	3,322	3,294	3,518	3,566	3,608	3,584	3,447	3,316	[illegible]	[illegible]	3,650	3,638	3,366	3,567	3,577	3,667
METED	2,221	2,262	2,298	2,318	2,330	2,351	2,324	2,342	[illegible]	[illegible]	[illegible]	2,451	2,433	2,467	2,492	2,510
PECO	5,827	5,840	6,068	6,154	6,155	6,180	6,085	6,031	6,259	6,294	[illegible]	6,411	6,257	6,441	6,500	6,560
PENLC	2,400	2,424	2,422	2,438	2,435	2,440	2,407	[illegible]	2,429	2,421	[illegible]	2,441	2,417	2,431	2,433	2,436
PEPCO	4,273	4,327	4,358	4,411	4,437	4,480	4,417	[illegible]	4,521	4,543	[illegible]	4,627	4,578	4,615	4,665	4,694
PL	5,859	5,912	6,019	6,101	6,103	6,117	6,036	[illegible]	6,188	6,207	[illegible]	[illegible]	6,213	6,337	6,408	6,465
PS	6,451	6,253	6,695	6,784	6,764	6,768	6,613	[illegible]	[illegible]	6,831	6,852	[illegible]	6,325	6,763	6,815	6,891
RECO	231	228	235	237	239	240	[illegible]	229	[illegible]	237	240	239	229	234	235	234
UGI	147	149	150	152	150	150	147	148	[illegible]	150	151	151	150	151	152	152
DIVERSITY - MID-ATLANTIC(-)	2,582	2,360	2,870	2,922	2,998	3,423	2,861	[illegible]	3,061	3,063	3,231	3,427	2,284	3,044	3,001	3,142
PJM MID-ATLANTIC	36,892	37,129	37,839	38,264	38,325	[illegible]	37,805	37,875	[illegible]	38,815	39,137	39,024	38,781	39,210	39,561	39,794
FE-EAST	7,488	7,511	7,656	7,694	7,793	[illegible]	[illegible]	7,618	[illegible]	7,811	7,914	7,959	7,765	7,851	7,891	8,000
PLGRP	5,866	5,886	6,016	6,069	6,050	[illegible]	6,031	[illegible]	6,130	6,165	6,195	6,224	6,185	6,312	6,371	6,428

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Table B-3

SPRING (APRIL) PEAK LOAD (MW) FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2016 - 2031

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
AEP	19,002	19,186	19,940	20,424	20,454	20,779	20,122	20,070	21,258	[illegible]	21,679	21,669	21,021	21,792	22,309	22,410
APS	7,094	7,309	7,479	7,621	7,655	7,695	7,623	7,657	7,864	[illegible]	8,012	8,023	7,958	8,113	8,172	8,259
ATSI	9,167	9,285	9,343	9,523	9,436	9,505	9,406	9,459	[illegible]	[illegible]	9,732	9,753	9,691	9,792	9,948	9,920
COMED	13,632	13,796	14,210	14,459	14,614	14,716	14,455	14,553	[illegible]	[illegible]	15,559	15,576	15,262	15,741	15,953	16,193
DAYTON	2,452	2,471	2,555	2,640	2,647	2,653	2,592	2,575	[illegible]	[illegible]	[illegible]	2,789	2,692	2,801	2,840	2,866
DEOK	3,839	3,917	4,077	4,149	4,145	4,187	4,052	4,093	4,307	4,326	[illegible]	4,419	4,292	4,490	4,552	4,584
DLCO	2,072	2,067	2,189	2,217	2,241	2,256	2,129	[illegible]	2,239	2,260	[illegible]	2,301	2,147	2,266	2,298	2,331
EKPC	1,662	1,687	1,703	1,726	1,733	1,760	1,738	[illegible]	1,795	1,799	[illegible]	1,824	1,800	1,818	1,855	1,863
DIVERSITY - WESTERN(-)	1,998	2,573	1,443	2,010	2,627	3,167	[illegible]	2,604	[illegible]	2,845	3,296	3,095	2,793	2,277	2,821	2,830
PJM WESTERN	56,922	57,145	60,053	60,749	60,298	60,384	[illegible]	59,646	[illegible]	62,394	62,954	63,259	62,070	64,536	65,106	65,596
DOM	15,690	16,166	16,755	17,263	17,595	17,763	17,496	[illegible]	18,113	18,413	18,757	18,910	18,576	18,866	19,193	19,559
DIVERSITY - INTERREGIONAL(-)	1,184	2,511	929	546	-619	[illegible]	1,599	2,905	[illegible]	-614	-786	-151	3,384	1,135	839	-756
PJM RTO	108,320	107,929	113,718	115,730	116,837	[illegible]	[illegible]	112,124	[illegible]	120,236	121,634	121,344	116,043	121,477	123,021	125,705

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Table B-4

FALL (OCTOBER) PEAK LOAD (MW) FOR
EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2016 - 2031

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
AE	1,417	1,430	1,442	1,445	1,419	1,416	1,413	1,418	1,434	[illegible]	1,424	1,423	1,425	1,444	1,443	1,435
BGE	4,646	4,742	4,787	4,814	4,774	4,761	4,770	4,843	4,921	[illegible]	4,945	4,919	4,966	5,054	5,083	5,091
DPL	2,634	2,720	2,839	2,837	2,804	2,800	2,727	2,784	2,898	[illegible]	2,903	2,899	2,877	3,009	3,017	3,002
JCPL	3,404	3,544	3,672	3,696	3,645	3,609	3,484	3,574	[illegible]	[illegible]	3,706	3,677	3,663	3,773	3,787	3,809
METED	2,139	2,205	2,244	2,271	2,236	2,219	2,237	2,279	[illegible]	[illegible]	[illegible]	2,328	2,381	2,429	2,454	2,470
PECO	5,774	6,027	6,180	6,207	6,135	6,099	6,006	6,196	6,313	6,349	[illegible]	6,351	6,428	6,561	6,610	6,641
PENLC	2,376	2,391	2,408	2,394	2,369	2,369	2,370	[illegible]	2,381	2,375	[illegible]	2,374	2,379	2,400	2,385	2,386
PEPCO	4,298	4,376	4,426	4,458	4,428	4,447	4,442	[illegible]	4,567	4,580	[illegible]	4,599	4,632	4,712	4,742	4,765
PL	5,697	5,830	5,986	6,014	5,900	5,849	5,845	[illegible]	6,092	6,091	6,090	[illegible]	6,093	6,270	6,306	6,312
PS	6,375	6,679	6,856	6,891	6,794	6,761	6,471	[illegible]	6,892	6,911	6,883	[illegible]	6,820	7,006	7,039	7,047
RECO	242	247	250	251	248	246	[illegible]	247	[illegible]	251	250	247	248	252	253	251
UGI	144	146	147	148	145	144	145	146	[illegible]	148	147	145	147	149	151	150
DIVERSITY - MID-ATLANTIC(-)	1,531	1,503	1,903	1,922	1,621	1,646	1,524	[illegible]	2,045	1,947	1,745	1,626	1,576	1,983	2,004	1,891
PJM MID-ATLANTIC	37,615	38,834	39,334	39,504	39,276	[illegible]	38,629	39,500	[illegible]	40,080	40,247	40,206	40,483	41,076	41,266	41,468
FE-EAST	7,605	7,812	7,966	8,003	7,931	[illegible]	[illegible]	7,905	[illegible]	8,067	8,072	8,018	8,117	8,228	8,257	8,304
PLGRP	5,802	5,932	6,096	6,110	6,016	[illegible]	5,955	[illegible]	6,168	6,165	6,178	6,102	6,192	6,349	6,374	6,380

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Table B-4

FALL (OCTOBER) PEAK LOAD (MW) FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2016 - 2031

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
AEP	18,322	18,781	19,441	19,803	19,205	19,262	19,367	19,740	20,633	[illegible]	20,370	20,451	20,729	21,583	21,924	21,813
APS	6,860	7,151	7,389	7,421	7,289	7,285	7,372	7,513	7,657	[illegible]	7,629	7,630	7,790	8,020	8,031	8,021
ATSI	8,983	9,104	9,160	9,221	9,153	9,184	9,234	9,305	[illegible]	[illegible]	9,451	9,470	9,552	9,662	9,726	9,752
COMED	13,757	14,135	14,545	14,694	14,560	14,539	14,550	14,806	[illegible]	[illegible]	15,407	15,421	15,629	16,036	16,191	16,313
DAYTON	2,398	2,465	2,568	2,602	2,561	2,554	2,513	2,559	[illegible]	[illegible]	[illegible]	2,688	2,680	2,804	2,834	2,827
DEOK	3,877	3,985	4,053	4,087	4,049	4,057	4,077	4,146	4,228	4,253	[illegible]	4,283	4,337	4,465	4,486	4,515
DLCO	1,995	2,024	2,181	2,165	2,150	2,160	2,034	[illegible]	2,190	2,202	[illegible]	2,217	2,094	2,277	2,271	2,275
EKPC	1,634	1,655	1,669	1,688	1,671	1,682	1,702	[illegible]	1,743	1,756	[illegible]	1,741	1,769	1,795	1,810	1,823
DIVERSITY - WESTERN(-)	2,055	2,059	1,303	1,527	840	1,080	[illegible]	2,284	[illegible]	1,465	1,005	1,476	2,389	1,815	2,038	1,663
PJM WESTERN	55,771	57,241	59,703	60,154	59,798	59,643	[illegible]	59,544	[illegible]	62,323	62,765	62,425	62,191	64,827	65,235	65,676
DOM	15,106	15,765	16,321	16,511	16,280	16,430	16,703	[illegible]	17,316	17,323	17,463	17,608	18,030	18,403	18,495	18,481
DIVERSITY - INTERREGIONAL(-)	2,501	2,996	2,568	2,466	2,083	[illegible]	2,391	2,601	[illegible]	2,322	2,274	2,579	2,631	2,360	2,196	2,113
PJM RTO	105,991	108,844	112,790	113,703	113,271	[illegible]	[illegible]	113,487	[illegible]	117,404	118,201	117,660	118,073	121,946	122,800	123,512

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Table B-5

MONTHLY PEAK FORECAST (MW) FOR
EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	MID-ATLANTIC DIVERSITY	PJM MID-ATLANTIC
Jan 2016	1,626	5,940	3,412	3,765	2,593	6,652	2,814	5,385	7,209	6,711	227	[illegible]92	704	45,822
Feb 2016	1,561	5,614	3,261	3,673	2,493	6,364	2,778	5,149	6,818	6,498	219	182	933	43,677
Mar 2016	1,379	5,044	2,917	3,205	2,368	5,872	2,576	4,573	6,376	5,981	[illegible]	167	1,491	39,173
Apr 2016	1,336	4,719	2,688	3,322	2,221	5,827	2,400	4,273	5,859	6,451	[illegible]	147	2,571	36,892
May 2016	1,699	5,522	3,018	4,141	2,429	6,666	2,465	5,253	5,933	7,634	[illegible]	147	1,785	43,418
Jun 2016	2,238	6,565	3,715	5,440	2,801	8,133	2,781	6,280	6,801	9,50[illegible]	379	174	676	54,140
Jul 2016	2,524	6,945	3,991	5,967	2,939	8,547	2,890	6,563	7,192	10,08[illegible]	407	[illegible]	1,068	57,174
Aug 2016	2,416	6,724	3,830	5,423	2,834	8,116	2,766	6,372	6,863	[illegible]65	367	[illegible]	722	54,527
Sep 2016	1,946	5,849	3,263	4,542	2,491	7,153	2,581	5,585	6,195	[illegible],140	316	157	942	47,276
Oct 2016	1,417	4,646	2,634	3,404	2,139	5,774	2,376	4,298	5,6[illegible]	6,375	242	144	1,531	37,615
Nov 2016	1,387	4,743	2,696	3,241	2,250	5,789	2,505	4,342	[illegible]	6,041	214	162	492	39,025
Dec 2016	1,614	5,523	3,172	3,820	2,519	6,500	2,807	5,202	[illegible]17	6,753	238	187	580	44,572

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	[illegible]	[illegible]	RECO	UGI	DIVERSITY	MID-ATLANTIC
Jan 2017	1,632	5,994	3,462	3,823	2,638	6,770	2,829	5,453	7,29[illegible]	[illegible]01	228	194	619	46,503
Feb 2017	1,569	5,659	3,318	3,717	2,534	6,491	2,794	5,206	6,917	[illegible]90	220	184	774	44,425
Mar 2017	1,388	5,095	2,956	3,258	2,418	5,968	2,59[illegible]	[illegible]600	6,481	[illegible]	208	170	1,444	39,763
Apr 2017	1,336	4,757	2,707	3,294	2,262	5,840	2,42[illegible]	[illegible]	5,912	6,[illegible]	228	149	2,360	37,129
May 2017	1,710	5,564	3,068	4,257	2,475	6,778	2,479	5,32[illegible]	[illegible]20	7,775	298	149	1,595	44,305
Jun 2017	2,244	6,601	3,762	5,515	2,849	8,258	2,807	6,326	[illegible]	9,581	382	176	686	54,693
Jul 2017	2,530	6,989	4,031	6,038	2,975	8,658	2,900	[illegible]614	[illegible]270	[illegible]3	409	190	1,041	57,736
Aug 2017	2,417	6,754	3,860	5,484	2,878	8,216	2,785	[illegible]20	6,905	9,[illegible]16	369	174	664	55,014
Sep 2017	1,956	5,870	3,310	4,607	2,526	[illegible]	2,586	[illegible]	6,289	8,214	317	158	1,077	47,622
Oct 2017	1,430	4,742	2,720	3,544	2,205	[illegible],027	[illegible]391	[illegible]	5,830	6,679	247	146	1,503	38,834
Nov 2017	1,401	4,797	2,742	3,292	2,2[illegible]	5,884	[illegible]520	4,[illegible]	6,242	6,104	215	164	547	39,496
Dec 2017	1,617	5,552	3,214	3,871	[illegible]	6,585	[illegible]801	5,25[illegible]	6,886	6,799	235	189	538	45,023

	AE	BGE	DPL	JCPL	[illegible]ED	PEC[illegible]	[illegible]	[illegible]PCO	PL	PS	RECO	UGI	DIVERSITY	MID-ATLANTIC
Jan 2018	1,640	6,044	3,507	3,881	2,[illegible]	[illegible]	2,837	[illegible]	7,385	6,869	229	196	627	47,010
Feb 2018	1,579	5,710	3,366	3,786	2,58[illegible]	[illegible]74	2,800	5,266	6,999	6,657	221	186	717	45,009
Mar 2018	1,387	5,118	2,980	[illegible]	2,451	[illegible]094	2,597	4,637	6,545	6,092	208	171	1,554	39,915
Apr 2018	1,343	4,818	2,785	[illegible]	[illegible]298	[illegible]	2,422	4,358	6,019	6,695	235	150	2,870	37,839
May 2018	1,716	5,606	3,[illegible]	4,324	[illegible]2	6,[illegible]	2,491	5,388	6,093	7,851	300	151	1,612	44,787
Jun 2018	2,251	6,652	[illegible]	5,564	2,[illegible]	8,34[illegible]	2,806	6,342	6,930	9,592	380	177	745	54,944
Jul 2018	2,534	7,060	[illegible]055	6,096	3,01[illegible]	8,745	2,904	6,630	7,338	10,234	411	191	1,023	58,194
Aug 2018	2,423	6,827	[illegible]02	5,534	2,906	8,293	2,786	6,445	6,973	9,435	369	175	691	55,367
Sep 2018	1,960	5,894	[illegible]	4,651	2,558	7,323	2,585	5,637	6,348	8,254	318	159	1,004	48,026
Oct 2018	1,442	4,787	2,83[illegible]	3,672	2,24[illegible]	6,180	2,408	4,426	5,986	6,856	250	147	1,903	39,334
Nov 2018	1,403	4,829	2,781	[illegible]322	2,3[illegible]	5,953	2,534	4,415	6,286	6,132	215	164	545	39,805
Dec 2018	1,633	5,606	3,259	[illegible]	[illegible]	6,667	2,826	5,319	6,982	6,881	237	191	735	45,386

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Table B-5

MONTHLY PEAK FORECAST (MW) FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	WESTERN DIVERSITY	PJM WEST[illegible]	DOM	INTER REGION DIVERSITY	PJM RTO
Jan 2016	22,511	8,508	10,547	15,430	2,848	4,421	2,158	2,596	1,199	67[illegible]	17,428	826	130,244
Feb 2016	21,483	8,144	10,426	15,179	2,745	4,247	2,089	2,358	1,429	[illegible]42	16,086	641	124,364
Mar 2016	20,468	7,760	9,695	13,798	2,547	3,905	1,989	2,053	1,798	[illegible]17	15,908	767	114,731
Apr 2016	19,002	7,094	9,167	13,632	2,452	3,839	2,072	1,662	1,998	[illegible]	15,690	1,184	108,320
May 2016	19,579	7,381	10,407	16,699	2,750	4,432	2,339	1,557	2,54[illegible]	62,[illegible]	17,010	3,437	119,595
Jun 2016	22,156	8,467	12,467	20,493	3,184	5,176	2,796	1,868	1,130	75,47[illegible]	18,688	4,206	144,099
Jul 2016	23,010	8,816	12,920	21,998	3,403	5,436	2,893	1,956	[illegible]75	78,857	[illegible]529	3,395	152,165
Aug 2016	22,785	8,643	12,587	21,323	3,337	5,386	2,828	1,947	[illegible]981	77,855	[illegible]5	3,681	147,926
Sep 2016	20,563	7,717	11,071	18,024	2,923	4,761	2,479	1,709	1,307	67,939	17,[illegible]	4,093	128,422
Oct 2016	18,322	6,860	8,983	13,757	2,398	3,877	1,995	1,[illegible]	2,055	55,771	15,10[illegible]	2,501	105,991
Nov 2016	19,328	7,315	9,397	13,933	2,504	3,796	1,947	[illegible]	1,194	58,964	14,797	1,882	110,904
Dec 2016	21,271	8,130	10,586	15,835	2,760	4,277	2,145	2[illegible]	1,0[illegible]	66,314	16,260	1,340	125,806

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	[illegible]RSITY	WESTERN	DOM	DIVERSITY	PJM RTO
Jan 2017	22,899	8,760	10,658	15,662	2,901	4,490	2,181	2,628	[illegible]95	68,984	18,064	1,066	132,485
Feb 2017	21,777	8,397	10,519	15,391	2,796	4,310	[illegible]15	2,390	[illegible]	66,111	16,687	678	126,545
Mar 2017	20,809	8,010	9,795	14,080	2,593	3,976	[illegible]	2,084	1,8[illegible]	61,546	16,416	1,981	115,744
Apr 2017	19,186	7,309	9,285	13,796	2,471	3,917	[illegible]067	[illegible]	2,573	57,145	16,166	2,511	107,929
May 2017	19,846	7,590	10,498	16,945	2,796	4,487	[illegible]58	1,[illegible]	2,496	63,599	17,507	3,969	121,442
Jun 2017	22,470	8,666	12,549	20,798	3,238	5,231	[illegible]4	[illegible]	[illegible]	76,406	19,209	4,140	146,168
Jul 2017	23,313	9,016	13,005	22,215	3,454	5,501	2,[illegible]	[illegible]76	1,[illegible]75	79,823	20,053	3,428	154,184
Aug 2017	23,066	8,827	12,666	21,597	3,[illegible]	[illegible]443	2,8[illegible]	1,962	886	78,910	19,712	3,720	149,916
Sep 2017	20,875	7,916	11,066	18,266	[illegible]49	[illegible]02	2,49[illegible]	1,723	1,471	68,617	17,924	4,421	129,742
Oct 2017	18,781	7,151	9,104	14,135	2,465	[illegible]5	2,024	1,655	2,059	57,241	15,765	2,996	108,844
Nov 2017	19,798	7,550	9,492	14,1[illegible]	2,545	[illegible]7	1,964	1,965	1,046	60,296	15,460	2,285	112,967
Dec 2017	21,611	8,333	10,651	1[illegible]	2,805	[illegible]18	2,154	[illegible]391	1,188	67,130	16,743	1,082	127,814

	AEP	APS	ATSI	COM[illegible]	[illegible]AY[illegible]	DEOK	[illegible]	EKPC	DIVERSITY	WESTERN	DOM	DIVERSITY	PJM RTO
Jan 2018	23,307	8,990	10,748	15,941	[illegible]	4,549	2,196	2,657	1,303	70,040	18,624	1,028	134,646
Feb 2018	22,159	8,612	10[illegible]	15,651	[illegible]9	4,354	2,127	2,414	1,781	66,983	17,189	590	128,591
Mar 2018	21,191	8,145	[illegible]	[illegible]76	2,[illegible]	4,040	2,016	2,103	1,770	62,509	17,014	2,292	117,146
Apr 2018	19,940	7,479	9,343	1[illegible]	2,55[illegible]	4,077	2,189	1,703	1,443	60,053	16,755	929	113,718
May 2018	20,213	7[illegible]	10,595	17,1[illegible]	2,844	[illegible]561	2,381	1,592	2,465	64,622	18,222	4,065	123,566
Jun 2018	22,767	[illegible]	12,643	20,927	3,276	5,294	2,839	1,891	1,291	77,129	19,675	4,245	147,503
Jul 2018	23,585	9[illegible]	13,089	22,437	[illegible],496	5,566	2,938	1,994	1,569	80,665	20,500	3,408	155,951
Aug 2018	23,351	8,9[illegible]	12,761	21,767	[illegible],424	5,502	2,873	1,973	925	79,669	20,166	4,806	150,396
Sep 2018	21,104	8,031	[illegible]102	18,354	[illegible],969	4,814	2,496	1,731	1,864	68,737	18,463	4,607	130,619
Oct 2018	19,441	7,389	[illegible]0	14,54[illegible]	2,568	4,053	2,181	1,669	1,303	59,703	16,321	2,568	112,790
Nov 2018	20,149	7,732	9,[illegible]	14,[illegible]	2,575	3,918	1,986	1,969	1,205	60,958	16,018	2,406	114,375
Dec 2018	22,045	8,512	10,8[illegible]	[illegible]4	2,856	4,387	2,186	2,430	1,328	68,213	17,204	1,163	129,640

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Table B-6

MONTHLY PEAK FORECAST (MW) FOR FE-EAST AND PLGRP

	FE_EAST	PLGRP
Jan 2016	9,095	7,387
Feb 2016	8,878	7,000
Mar 2016	7,905	6,423
Apr 2016	7,488	5,866
May 2016	8,691	5,971
Jun 2016	10,893	6,975
Jul 2016	11,538	7,336
Aug 2016	10,955	7,036
Sep 2016	9,361	6,339
Oct 2016	7,605	5,802
Nov 2016	7,919	[illegible]
Dec 2016	9,132	[illegible]

	FE_EAST	[illegible]
Jan 2017	9,229	[illegible]
Feb 2017	8,983	[illegible]
Mar 2017	7,962	6,499
Apr [illegible]	[illegible]	5,886
May [illegible]	[illegible]	6,054
Jun [illegible]	[illegible]	[illegible]
Jul [illegible]	[illegible]	[illegible]
Aug [illegible]	[illegible]	[illegible]
Sep 2017	[illegible]	6,426
Oct 2017	[illegible]	5,932
[illegible] 2017	[illegible]	6,401
[illegible] 2017	[illegible]	7,074

	FE_EA[illegible]	PLGRP
[illegible]	[illegible]	7,566
Feb [illegible]	[illegible]	7,173
Mar 2018	8,032	6,578
Apr 2018	7,656	6,016
May 2018	8,963	6,129
Jun 2018	11,072	7,107
[illegible] 2018	11,762	7,487
Aug 2018	11,107	7,149
Sep 2018	9,511	6,489
Oct 2018	7,966	6,096
Nov 2018	8,095	6,450
Dec 2018	9,314	7,158

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Table B-8

DISTRIBUTED SOLAR ADJUSTMENTS TO SUMMER PEAK LOAD (MW) FOR EACH PJM ZONE AND RTO
2016-2031

Zone	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
AE	69	74	75	77	78	80	83	86	90	97	107	118	130	144	159	173
BGE	35	47	59	68	72	73	74	76	78	82	[illegible]	93	103	116	130	146
DPL	40	47	57	65	71	77	86	96	104	112	[illegible]	130	142	158	178	205
JCPL	100	107	110	112	115	118	122	127	134	145	[illegible]	180	200	223	246	270
METED	10	11	12	13	14	15	16	16	17	18	[illegible]	19	20	21	22	23
PECO	13	15	17	20	23	24	26	27	29	[illegible]	[illegible]	34	35	37	40	43
PENLC	4	6	8	9	11	13	14	15	16	[illegible]	18	19	20	22	23	25
PEPCO	24	32	40	46	49	50	51	53	55	58	61	66	72	81	90	100
PL	28	32	35	38	42	44	46	48	50	52	54	[illegible]	59	61	65	69
PS	125	136	141	145	149	154	160	169	[illegible]	197	220	[illegible]	280	315	351	387
RECO	3	3	3	4	4	4	4	4	[illegible]	5	6	[illegible]	8	9	11	12
UGI	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1
AEP	18	26	35	44	55	67	80	95	[illegible]	[illegible]	143	156	169	184	201	222
APS	9	12	16	19	21	22	24	26	[illegible]	30	32	35	38	42	47	53
ATSI	18	22	27	32	37	43	48	53	[illegible]	65	71	73	74	76	77	80
COMED	19	24	28	32	36	42	[illegible]	58	66	74	83	91	99	108	116	126
DAYTON	3	4	5	6	7	9	[illegible]	11	12	[illegible]	15	15	15	16	16	16
DEOK	3	5	6	7	9	10	[illegible]	[illegible]	15	[illegible]	18	19	19	19	20	20
DLCO	2	3	4	5	6	7	[illegible]	8	[illegible]	10	10	11	11	12	13	14
EKPC	0	0	0	0	0	0	0	0	[illegible]	1	1	1	1	1	1	2
DOM	50	72	86	103	124	[illegible]	175	[illegible]	237	270	304	340	378	419	464	513
PJM RTO	576	680	765	847	[illegible]	1,001	1,090	[illegible]	1,296	1,419	1,562	1,712	1,876	2,064	2,273	2,501

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Note: Adjustment values presented here are reflected in Tables B-1 through B-6 and Tables B-10 and B-11
Adjustments reflect the impact of historical distributed solar generation and forecasted distributed solar generation

Table B-9

ADJUSTMENTS TO SUMMER PEAK LOAD (MW) FOR EACH PJM ZONE AND RTO 2016 - 2031

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
AE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BGE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DPL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
JCPL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
METED	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PECO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PENLC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PEPCO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RECO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
UGI	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AEP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
APS	120	220	250	280	280	270	26[illegible]	260	250	240	230	230	220	210	210	200
ATSI	0	0	0	0	0	0	[illegible]	0	0	0	0	0	0	0	0	0
COMED	0	0	0	0	0	0	[illegible]	[illegible]	0	[illegible]	0	0	0	0	0	0
DAYTON	0	0	0	0	0	0	[illegible]	0	[illegible]	0	0	0	0	0	0	0
DEOK	0	0	0	0	0	0	0	0	[illegible]	0	0	0	0	0	0	0
DLCO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EKPC	0	0	0	0	0	0	0	[illegible]	0	0	0	0	0	0	0	0
DOM	240	410	560	680	[illegible]	810	860	[illegible]	930	960	990	1,010	1,020	1,040	1,050	1,050
PJM RTO	360	630	810	960	[illegible],010	1,08[illegible]	1,120	1,1[illegible]	1,180	1,200	1,220	1,240	1,240	1,250	1,260	1,250

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Notes:
Adjustment values presented here are reflected in Tables B-1 through B-6 and Tables B-10, B-11 and B12.
Adjustments are large, unanticipated load changes deemed by PJM to not be captured in the forecast model.

Table B-10

SUMMER COINCIDENT PEAK LOAD (MW) FOR
EACH PJM ZONE, LOCATIONAL DELIVERABILITY AREA AND RTO
2016 - 2031

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
AE	2,435	2,442	2,447	2,445	2,430	2,418	2,414	2,415	2,414	[illegible]	2,409	2,405	2,404	2,402	2,392	2,389
BGE	6,663	6,716	6,766	6,758	6,778	6,763	6,773	6,814	6,833	[illegible]	6,917	6,924	6,965	7,015	7,013	7,072
DPL	3,838	3,878	3,907	3,916	3,917	3,908	3,912	3,926	3,941	[illegible]	3,977	3,982	4,003	4,023	4,027	4,038
JCPL	5,749	5,820	5,883	5,891	5,859	5,860	5,856	5,871	[illegible]	[illegible]	5,916	5,946	5,958	5,996	5,992	6,020
METED	2,824	2,856	2,907	2,937	2,931	2,940	2,949	2,961	[illegible]	3,034	[illegible]	3,087	3,100	3,148	3,183	3,211
PECO	8,254	8,363	8,455	8,498	8,500	8,491	8,527	8,587	[illegible]	8,695	[illegible]	8,837	8,923	9,010	9,076	9,144
PENLC	2,764	2,774	2,776	2,779	2,781	2,769	2,768	2,772	[illegible]	2,772	[illegible]	2,785	2,790	2,794	2,798	2,798
PEPCO	6,287	6,332	6,352	6,388	6,414	6,405	6,383	[illegible]	6,427	6,471	[illegible]	6,525	6,528	6,558	6,582	6,631
PL	6,906	6,982	7,051	7,083	7,059	7,073	7,095	[illegible]	7,167	7,205	7,243	[illegible]	7,350	7,412	7,452	7,501
PS	9,719	9,787	9,863	9,868	9,841	9,818	9,810	[illegible]	9,805	9,830	9,843	9,869	9,879	9,896	9,875	9,906
RECO	388	391	393	393	392	391	391	[illegible]	[illegible]	392	392	392	393	393	393	393
UGI	180	182	183	183	182	181	181	[illegible]	[illegible]	182	183	183	184	184	185	185
AEP	22,146	22,442	22,706	22,896	22,868	23,005	23,146	23,347	[illegible]	23,689	23,852	24,075	24,313	24,539	24,748	24,920
APS	8,496	8,699	8,817	8,897	8,901	8,926	8,964	9,031	[illegible]	9,142	9,195	9,256	9,329	9,400	9,461	9,531
ATSI	12,396	12,476	12,545	12,617	12,581	[illegible]	[illegible]	12,692	[illegible]	12,801	12,845	12,922	12,977	13,057	13,143	13,193
COMED	21,210	21,454	21,692	21,853	21,862	21,97[illegible]	[illegible]	22,268	[illegible]	22,618	22,776	22,987	23,192	23,339	23,594	23,789
DAYTON	3,229	3,276	3,317	3,344	3,330	3,341	3,359	[illegible]	3,416	3,435	3,455	3,482	3,514	3,550	3,577	3,600
DEOK	5,193	5,259	5,330	5,375	5,386	5,403	5,433	[illegible]	[illegible]	5,573	5,607	5,645	5,700	5,756	5,809	5,856
DLCO	2,772	2,796	2,818	2,827	2,817	2,819	[illegible]	2,831	[illegible]	2,848	2,858	2,874	2,889	2,905	2,917	2,928
EKPC	1,889	1,909	1,928	1,944	[illegible]	1,959	[illegible]	1,983	2,000	2,011	2,022	2,036	2,049	2,067	2,082	2,097
DOM	18,827	19,348	19,814	[illegible]	20,147	[illegible]	[illegible]	20,718	20,918	21,096	21,272	21,493	21,727	21,966	22,131	22,279
PJM RTO	152,165	154,182	155,950	[illegible]	156,92[illegible]	[illegible]	158,01[illegible]	159,007	160,020	160,973	161,913	163,008	164,167	165,410	166,430	167,481
PJM MID-ATLANTIC	56,007	56,523	56,983	[illegible]	[illegible]	57,017	[illegible]	57,272	57,474	57,760	58,031	58,238	58,477	58,831	58,968	59,288
EASTERN MID-ATLANTIC	30,383	30,681	30,948	31,01[illegible]	[illegible]	30,886	30,910	31,010	31,083	31,202	31,333	31,431	31,560	31,720	31,755	31,890
SOUTHERN MID-ATLANTIC	12,950	13,048	[illegible]	13,146	[illegible]	13,168	13,156	13,220	13,260	13,365	13,428	13,449	13,493	13,573	13,595	13,703
MID-ATLANTIC and APS	64,503	65,[illegible]	65,800	[illegible]	[illegible]	65,943	66,023	66,303	66,558	66,902	67,226	67,494	67,806	68,231	68,429	68,819

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Notes:
Load values for Zones and Locational Deliverability Areas are coincident with the PJM RTO peak.
This table will be used for the Reliability Pricing Model.

Table C-1

PJM LOCATIONAL DELIVERABILITY AREAS
CENTRAL MID-ATLANTIC: BGE, METED, PEPCO, PL and UGI
SEASONAL PEAKS - MW

BASE (50/50) FORECAST

YEAR	SPRING (WK 14-19)	SUMMER (WK 20-39)	FALL (WK 40-45)	WINTER (WK 46-13)
2016	16,762	23,492	16,343	21,160
2017	16,898	23,726	16,571	21,455
2018	17,183	23,925	16,81[illegible]	[illegible],670
2019	17,308	24,039	16,88[illegible]	[illegible]10
2020	17,300	24,018	[illegible]69	[illegible]
2021	17,364	24,018	[illegible],774	21,7[illegible]
2022	17,305	24,087	16,851	21,875
2023	17,286	24,182	17,002	21,934
2024	17,621	24,303	17,190	22,041
2025	17,629	24,440	17,[illegible]	22,120
2026	17,824	24,563	[illegible]	22,222
2027	17,901	24,683	[illegible]42	22,351
2028	17,815	24,833	[illegible]581	22,531
2029	18,026	25,007	[illegible]7	22,636
2030	18,139	[illegible]	17,[illegible]	22,748
2031	18,190	25,2[illegible]	17,95[illegible]	22,856

EXTREME WEA[illegible]ER [illegible]0) FORECAST

YEAR	[illegible] (WK 14-19)	SU[illegible]ER (WK [illegible]9)	FALL (WK 40-45)	WINTER (WK 46-13)
2016	17,223	24,9[illegible]	17,592	22,050
2017	17,353	25,23[illegible]	17,965	22,289
2018	17,59[illegible]	25,259	18,433	22,545
2019	17[illegible]	[illegible]6	18,517	22,674
2020	[illegible]30	25,635	18,298	22,613
[illegible]	[illegible]123	25,632	18,213	22,627
[illegible]	[illegible]3	25,622	18,096	22,693
2023	17,[illegible]	25,762	18,422	22,779
2024	18,07[illegible]	25,889	18,784	22,887
2025	18,313	26,138	18,786	22,981
2026	18,623	26,267	18,818	23,079
2027	18,714	26,394	18,835	23,200
2028	18,465	26,489	19,076	23,334
[illegible]029	18,656	26,464	19,386	23,483
[illegible]0	18,798	26,814	19,486	23,588
[illegible]	19,132	27,081	19,492	23,709

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Table C-2

PJM LOCATIONAL DELIVERABILITY AREAS
WESTERN MID-ATLANTIC: METED, PENLC, PL and UGI
SEASONAL PEAKS - MW

BASE (50/50) FORECAST

YEAR	SPRING (WK 14-19)	SUMMER (WK 20-39)	FALL (WK 40-45)	WINTER (WK 46-13)
2016	10,283	13,028	10,197	12,734
2017	10,338	13,161	10,407	12,880
2018	10,540	13,268	10,55[illegible]	[illegible],023
2019	10,618	13,335	10,59[illegible]	[illegible]94
2020	10,603	13,318	[illegible]50	[illegible]
2021	10,606	13,334	[illegible],353	13,0[illegible]
2022	10,605	13,381	10,434	13,097
2023	10,555	13,429	10,553	13,112
2024	10,767	13,501	10,664	13,184
2025	10,839	13,574	10,6[illegible]	13,231
2026	10,902	13,658	[illegible]	13,258
2027	10,920	13,750	[illegible]044	13,324
2028	10,875	13,833	[illegible]821	13,420
2029	11,053	13,935	[illegible]	13,473
2030	11,137	[illegible]	11,[illegible]	13,536
2031	11,209	14,1[illegible]	10,98[illegible]	13,602

EXTREME WEA[illegible]ER [illegible]0) FORECAST

YEAR	[illegible] (WK 14-19)	SU[illegible]ER (WK [illegible]9)	FALL (WK 40-45)	WINTER (WK 46-13)
2016	10,523	13,8[illegible]	10,460	13,151
2017	10,584	13,97[illegible]	10,684	13,304
2018	10,7[illegible]	[illegible]073	10,892	13,449
2019	10[illegible]	[illegible]6	10,940	13,518
2020	[illegible]44	14,142	10,824	13,467
[illegible]	[illegible]823	14,150	10,685	13,459
[illegible]	[illegible]	14,203	10,717	13,490
2023	10,[illegible]	14,268	10,867	13,531
2024	11,02[illegible]	14,345	11,071	13,589
2025	11,100	14,471	11,080	13,629
2026	11,142	14,514	11,071	13,676
2027	11,180	14,614	11,001	13,741
2028	11,097	14,717	11,166	13,809
[illegible]029	11,195	14,796	11,409	13,881
[illegible]	11,341	14,911	11,470	13,941
2[illegible]	11,441	15,063	11,484	13,995

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Table C-3

PJM LOCATIONAL DELIVERABILITY AREAS
EASTERN MID-ATLANTIC: AE, DPL, JCPL, PECO, PS and RECO
SEASONAL PEAKS - MW

BASE (50/50) FORECAST

YEAR	SPRING (WK 14-19)	SUMMER (WK 20-39)	FALL (WK 40-45)	WINTER (WK 46-13)
2016	18,796	31,278	19,695	22,194
2017	18,629	31,599	20,365	22,499
2018	19,884	31,716	20,9[illegible]	[illegible],740
2019	20,081	31,924	21,06[illegible]	[illegible]22
2020	20,048	31,885	[illegible]94	[illegible]
2021	19,829	31,709	[illegible],543	22,7[illegible]
2022	19,318	31,855	20,168	22,781
2023	18,966	31,930	20,688	22,852
2024	20,120	32,019	21,136	22,949
2025	20,393	32,191	21,[illegible]	23,004
2026	20,374	32,315	[illegible]	23,092
2027	20,350	32,292	[illegible]028	23,211
2028	19,266	32,509	[illegible]215	23,365
2029	20,388	32,568	[illegible]7	23,496
2030	20,468	[illegible]	21,[illegible]	23,626
2031	20,771	32,9[illegible]	21,69[illegible]	23,706

EXTREME WEA[illegible]ER ([illegible]0) FORECAST

YEAR	[illegible] (WK 14-19)	SU[illegible]ER (WK [illegible]9)	FALL (WK 40-45)	WINTER (WK 46-13)
2016	21,250	33,4[illegible]	23,182	22,860
2017	21,294	33,99[illegible]	23,841	23,140
2018	21,65[illegible]	34,023	24,599	23,412
2019	21,[illegible]	[illegible]8	24,428	23,524
2020	[illegible]09	34,170	23,976	23,417
[illegible]	[illegible],464	34,081	23,712	23,394
[illegible]	[illegible]3	34,070	23,647	23,408
2023	21,[illegible]	34,367	24,130	23,475
2024	22,02[illegible]	34,422	24,572	23,570
2025	22,121	34,609	24,893	23,617
2026	22,224	34,648	24,347	23,704
2027	22,909	34,720	24,232	23,835
2028	22,184	35,023	24,660	23,963
[illegible]029	22,427	34,932	25,283	24,095
[illegible]	22,648	35,219	25,266	24,199
[illegible]	22,749	35,449	25,610	24,302

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Table C-4

PJM LOCATIONAL DELIVERABILITY AREAS
SOUTHERN MID-ATLANTIC: BGE and PEPCO
SEASONAL PEAKS - MW

BASE (50/50) FORECAST

YEAR	SPRING (WK 14-19)	SUMMER (WK 20-39)	FALL (WK 40-45)	WINTER (WK 46-13)
2016	8,638	13,393	8,719	11,306
2017	8,690	13,492	8,874	11,415
2018	8,778	13,579	9,04[illegible]	[illegible],491
2019	8,828	13,624	9,072	[illegible]41
2020	8,856	13,662	[illegible]76	[illegible]
2021	8,931	13,653	[illegible],952	11,6[illegible]
2022	8,883	13,636	8,974	11,649
2023	8,892	13,678	9,125	11,686
2024	9,033	13,741	9,245	11,700
2025	9,107	13,857	9,2[illegible]	11,794
2026	9,140	13,912	[illegible]	11,845
2027	9,204	13,958	[illegible]59	11,905
2028	9,149	13,968	[illegible]82	11,988
2029	9,210	14,044	[illegible]	12,008
2030	9,324	[illegible]	9,[illegible]	12,068
2031	9,390	14,2[illegible]	9,57[illegible]	12,162

EXTREME WEA[illegible]ER [illegible]0) FORECAST

YEAR	[illegible] (WK 14-19)	SU[illegible]ER (WK [illegible]9)	FALL (WK 40-45)	WINTER (WK 46-13)
2016	9,534	14,2[illegible]	9,831	11,802
2017	9,542	14,39[illegible]	10,089	11,903
2018	9,69[illegible]	14,430	10,324	12,016
2019	[illegible]	[illegible]5	10,348	12,066
2020	[illegible]07	14,471	10,215	12,066
[illegible]	[illegible]769	14,489	10,185	12,088
[illegible]	[illegible]	14,535	10,069	12,123
2023	9,[illegible]	14,587	10,325	12,169
2024	9,918	14,587	10,487	12,222
2025	9,979	14,667	10,530	12,271
2026	10,093	14,742	10,513	12,326
2027	10,098	14,814	10,474	12,385
2028	10,048	14,908	10,646	12,452
[illegible]029	10,217	14,947	10,758	12,523
[illegible]	10,259	14,982	10,803	12,580
2[illegible]	10,331	15,063	10,848	12,641

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Table D-1

SUMMER EXTREME WEATHER (90/10) PEAK LOAD FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION 2016 - 2031

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
AE	2,637	2,650	2,647	2,659	2,634	2,625	2,623	2,625	2,630	[illegible]	2,619	2,617	2,620	2,611	2,615	2,616
BGE	7,367	7,432	7,445	7,450	7,462	7,473	7,499	7,534	7,531	[illegible]	7,617	7,652	7,704	7,722	7,735	7,776
DPL	4,159	4,205	4,221	4,249	4,230	4,237	4,246	4,256	4,274	[illegible]	4,297	4,319	4,341	4,349	4,371	4,381
JCPL	6,481	6,562	6,589	6,653	6,591	6,588	6,601	6,615	[illegible]	[illegible]	6,664	6,695	6,726	6,732	6,792	6,830
METED	3,043	3,120	3,121	3,178	3,180	3,195	3,186	3,240	[illegible]	3,29[illegible]	[illegible]322	3,359	3,391	3,388	3,452	3,491
PECO	9,009	9,144	9,210	9,260	9,264	9,297	9,353	9,411	9,443	9,525	[illegible]	9,690	9,783	9,838	9,917	10,023
PENLC	3,027	3,049	3,047	3,045	3,044	3,039	3,043	3,05[illegible]	3,043	3,051	[illegible]	3,064	3,078	3,078	3,080	3,090
PEPCO	6,904	6,962	6,985	7,005	7,010	7,016	7,036	[illegible]	7,056	7,093	[illegible]	7,162	7,204	7,225	7,247	7,287
PL	7,557	7,674	7,700	7,726	7,779	7,744	7,795	[illegible]	7,837	7,974	7,998	[illegible]015	8,118	8,127	8,171	8,318
PS	10,874	10,989	10,904	11,039	11,003	10,886	10,996	[illegible]012	10,97[illegible]	11,023	11,018	[illegible]0,949	11,103	10,950	11,073	11,147
RECO	444	448	452	449	448	448	[illegible]	448	[illegible]	449	449	450	451	453	451	452
UGI	202	205	206	207	205	204	203	204	[illegible]	206	205	206	207	208	209	210
DIVERSITY - MID-ATLANTIC(-)	540	617	537	1	431	324	537	[illegible]	0	163	470	332	630	537	0	151
PJM MID-ATLANTIC	61,164	61,823	61,990	62,919	62,419	62,[illegible]28	62,492	62,686	[illegible]354	63,637	63,504	63,846	64,096	64,144	65,113	65,470
FE-EAST	12,422	12,564	12,661	12,714	12,688	[illegible]	[illegible]	12,740	12,[illegible]	12,860	12,912	12,962	13,028	13,097	13,162	13,248
PLGRP	7,759	7,879	7,906	7,933	7,983	7,[illegible]	7,998	[illegible]	8,04[illegible]	8,179	8,203	8,221	8,325	8,335	8,379	8,527

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Table D-1

SUMMER EXTREME WEATHER (90/10) PEAK LOAD FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO 2016 - 2031

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
AEP	23,953	24,304	24,437	24,605	24,677	24,898	25,090	25,279	25,320	[illegible]	25,758	26,092	26,340	26,469	26,633	26,894
APS	9,008	9,248	9,362	9,440	9,426	9,466	9,519	9,619	9,647	[illegible]	9,749	9,834	9,953	10,017	10,069	10,110
ATSI	13,454	13,571	13,623	13,654	13,664	13,708	13,765	13,820	[illegible]	[illegible]	13,979	14,063	14,156	14,224	14,266	14,362
COMED	24,085	24,289	24,453	24,691	24,645	24,791	25,041	25,139	[illegible]	[illegible]	25,666	25,905	26,155	26,336	26,561	26,814
DAYTON	3,548	3,587	3,619	3,653	3,640	3,657	3,693	3,706	[illegible]	[illegible]	3,779	3,811	3,847	3,874	3,906	3,933
DEOK	5,678	5,743	5,788	5,828	5,847	5,882	5,935	5,960	5,992	6,044	[illegible]	6,146	6,196	6,247	6,290	6,351
DLCO	3,026	3,057	3,068	3,075	3,073	3,075	3,083	[illegible]	3,091	3,106	[illegible]	3,139	3,158	3,167	3,177	3,196
EKPC	2,107	2,134	2,146	2,163	2,166	2,189	2,203	[illegible]	2,235	2,254	[illegible]	2,289	2,303	2,327	2,343	2,366
DIVERSITY - WESTERN(-)	448	585	275	210	195	388	[illegible]	564	[illegible]	331	289	482	580	347	198	307
PJM WESTERN	84,411	85,348	86,221	86,899	86,943	87,278	[illegible]	88,269	[illegible]	89,506	90,118	90,797	91,528	92,314	93,047	93,719
DOM	20,433	20,992	21,389	21,685	21,790	21,993	22,195	[illegible]	22,531	22,776	22,983	23,230	23,468	23,669	23,837	24,055
DIVERSITY - INTERREGIONAL(-)	2,257	2,004	1,731	2,300	1,974	[illegible]	2,331	1,935	[illegible]	2,268	1,968	2,030	1,979	1,897	2,322	2,375
PJM RTO	163,751	166,159	167,869	169,203	169,178	[illegible]	[illegible]	171,411	[illegible]	173,651	174,637	175,843	177,113	178,230	179,675	180,869

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Table D-2

WINTER EXTREME WEATHER (90/10) PEAK LOAD FOR
EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2015/16 - 2030/31

	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31
AE	1,674	1,679	1,685	1,685	1,671	1,667	1,663	1,662	1,663	[illegible]	1,665	1,670	1,675	1,679	1,682	1,683
BGE	6,184	6,230	6,281	6,303	6,297	6,309	6,324	6,349	6,372	[illegible]	6,427	6,455	6,487	6,519	6,546	6,578
DPL	3,565	3,613	3,659	3,682	3,683	3,694	3,707	3,728	3,749	[illegible]	3,794	3,817	3,841	3,869	3,891	3,919
JCPL	3,846	3,902	3,955	3,992	3,946	3,931	3,934	3,944	[illegible]	[illegible]	3,951	3,970	4,012	4,018	4,079	4,061
METED	2,662	2,716	2,758	2,790	2,784	2,782	2,787	2,813	[illegible]	2,83[illegible]	[illegible]	2,876	2,898	2,924	2,967	2,970
PECO	6,840	6,938	7,023	7,064	7,029	7,037	7,059	7,094	7,132	7,164	[illegible]	7,246	7,292	7,344	7,377	7,424
PENLC	2,870	2,886	2,896	2,906	2,883	2,881	2,883	2,88[illegible]	2,891	2,883	[illegible]	2,882	2,890	2,889	2,911	2,893
PEPCO	5,624	5,673	5,735	5,763	5,769	5,783	5,799	[illegible]	5,850	5,877	[illegible]	5,939	5,973	6,010	6,036	6,071
PL	7,427	7,509	7,596	7,630	7,606	7,610	7,622	[illegible]	7,681	7,709	7,743	[illegible]	7,820	7,867	7,894	7,939
PS	6,817	6,887	6,945	6,979	6,947	6,918	6,931	[illegible]	6,95[illegible]	6,950	6,971	[illegible]	7,035	7,053	7,118	7,100
RECO	236	239	240	241	238	238	[illegible]	240	[illegible]	238	238	239	240	240	243	241
UGI	201	202	204	204	202	201	201	[illegible]	[illegible]	201	201	201	201	201	202	202
DIVERSITY - MID-ATLANTIC(-)	572	332	282	330	308	394	328	[illegible]	313	407	433	491	318	327	428	439
PJM MID-ATLANTIC	47,374	48,142	48,695	48,909	48,747	[illegible]	48,821	48,983	[illegible]	49,229	49,408	49,589	50,046	50,286	50,518	50,642
FE-EAST	9,350	9,462	9,568	9,644	9,568	[illegible]	[illegible]	9,592	[illegible]	9,637	9,675	9,722	9,772	9,829	9,895	9,896
PLGRP	7,628	7,711	7,800	7,834	7,808	[illegible]	7,822	[illegible]	7,88[illegible]	7,909	7,943	7,983	8,021	8,068	8,095	8,140

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Table D-2

WINTER EXTREME WEATHER (90/10) PEAK LOAD FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2015/16 - 2030/31

	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31
AEP	23,846	24,238	24,708	24,889	24,939	25,101	25,344	25,515	25,808	[illegible]	26,218	26,463	26,763	27,040	27,220	27,488
APS	8,970	9,220	9,451	9,541	9,580	9,628	9,672	9,730	9,801	[illegible]	9,919	9,980	10,053	10,123	10,176	10,251
ATSI	10,833	10,921	11,021	11,091	11,055	11,073	11,108	11,160	[illegible]	[illegible]	11,308	11,357	11,404	11,461	11,513	11,562
COMED	16,026	16,265	16,486	16,682	16,643	16,697	16,803	16,937	[illegible]	[illegible]	17,372	17,499	17,663	17,802	17,995	18,136
DAYTON	2,961	3,010	3,065	3,096	3,080	3,085	3,105	3,128	[illegible]	[illegible]	[illegible]	3,214	3,242	3,269	3,292	3,309
DEOK	4,660	4,720	4,784	4,807	4,793	4,853	4,923	4,918	4,957	4,960	[illegible]	5,073	5,143	5,157	5,160	5,202
DLCO	2,202	2,222	2,240	2,250	2,238	2,235	2,237	[illegible]	2,252	2,252	[illegible]	2,269	2,278	2,288	2,299	2,301
EKPC	2,912	2,940	2,977	2,994	3,010	3,030	3,048	[illegible]	3,088	3,112	[illegible]	3,156	3,177	3,199	3,222	3,251
DIVERSITY - WESTERN(-)	1,082	917	964	1,012	1,101	1,222	[illegible]	1,089	[illegible]	1,280	1,329	1,349	1,176	1,115	1,258	1,462
PJM WESTERN	71,328	72,619	73,768	74,338	74,237	74,480	[illegible]	75,612	[illegible]	76,562	77,080	77,662	78,547	79,224	79,619	80,038
DOM	18,508	19,128	19,673	20,058	20,204	20,365	20,583	[illegible]	21,050	21,276	21,498	21,735	21,972	22,222	22,433	22,664
DIVERSITY - INTERREGIONAL(-)	361	738	786	792	711	[illegible]	799	763	[illegible]	554	466	418	852	875	800	550
PJM RTO	136,849	139,151	141,350	142,513	142,477	[illegible]	[illegible]	144,652	[illegible]	146,513	147,520	148,568	149,713	150,857	151,770	152,794

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Table F-1

PJM RTO HISTORICAL PEAKS
(MW)

SUMMER

YEAR	NORMALIZED BASE	NORMALIZED COOLING	NORMALIZED TOTAL	UNRESTRICTED PEAK	PEAK DATE	TIME
1998				13[illegible]	Tuesday, July 21, 1998	17:00
1999	89,051			[illegible]21	Friday, July 30, 1999	17:00
2000	91,069	47,601	138,670	[illegible]803	Wednesday, August 9, 2000	17:00
2001	92,113	50,072	142,185	[illegible]	Thursday, August 9, 2001	16:00
2002	92,690	54,195	146,885	150,[illegible]	Thursday, August 1, 2002	17:00
2003	93,653	52,902	146,555	145,2[illegible]	Thursday, August 21, 2003	17:00
2004	95,169	53,091	148,260	139,219	Tuesday, August 3, 2004	17:00
2005	95,786	58,994	154,780	155,209	Tuesday, July 26, 2005	16:00
2006	95,253	62,147	157,400	166,866	Wednesday, August 2, 2006	17:00
2007	96,680	62,975	159,655	161,988	Wednesday, August 8, 2007	16:00
2008	97,144	62,426	159,570	150,560	Monday, June 9, 2008	17:00
2009	94,670	57,120	151,790	145,056	Monday, August 10, 2009	16:00
2010	93,133	61,112	154,245	157,188	Wednesday, July 7, 2010	17:00
2011	93,328	60,032	153,360	165,466	Thursday, July 21, 2011	17:00
2012	92,948	60,997	153,945	158,128	Tuesday, July 17, 2012	18:00
2013	92,464	56,936	149,400	159,039	Thursday, July 18, 2013	17:00
2014	91,837	58,268	[illegible]	141,402	Tuesday, June 17, 2014	18:00
2015	91,108	59,187	150,[illegible]	143,497	Tuesday, July 28, 2015	17:00

[illegible]TER

YEAR	NORMALIZED BASE	NORMALIZED HE[illegible]G	NORMAL[illegible]D TOTAL	UNRESTRICTED PEAK	PEAK DATE	TIME
97/98				103,235	Wednesday, January 14, 1998	19:00
98/99	87,537			116,078	Tuesday, January 5, 1999	19:00
99/00	89,288	26,[illegible]	115,58[illegible]	118,438	Thursday, January 27, 2000	20:00
00/01	91,324	26,[illegible]	117,74[illegible]	118,051	Wednesday, December 20, 2000	19:00
01/02	92,410	23,61[illegible]	[illegible]20	112,221	Wednesday, January 2, 2002	19:00
02/03	92,591	27,879	120,470	129,972	Thursday, January 23, 2003	19:00
03/04	93,710	28,970	122,680	122,357	Friday, January 23, 2004	9:00
04/05	94,387	[illegible]3	124,390	131,164	Monday, December 20, 2004	19:00
05/06	94,643	32,[illegible]	126,900	126,703	Wednesday, December 14, 2005	19:00
06/07	96,076	34,00[illegible]	130,080	136,739	Monday, February 5, 2007	20:00
07/08	97,180	34,870	132,050	128,313	Wednesday, January 2, 2008	19:00
08/09	96,326	32,774	129,100	134,021	Friday, January 16, 2009	19:00
09/10	93,425	34,945	128,370	125,276	Monday, January 4, 2010	19:00
10/11	91,823	36,977	128,800	132,228	Tuesday, December 14, 2010	19:00
11/12	92,284	34,056	126,340	124,420	Tuesday, January 3, 2012	19:00
12/13	92,061	33,9[illegible]	125,980	128,724	Tuesday, January 22, 2013	19:00
13/14	91,120	[illegible]	129,140	141,746	Tuesday, January 7, 2014	19:00
14/15	90,162	[illegible]108	128,270	142,762	Friday, February 20, 2015	8:00

Notes:
Normalized values for 2005 - 2015 are calculated by PJM staff using a methodology consistent with the PJM Load Forecast Model.
Normalized base values are calculated by PJM staff using a two-period average of peak loads on non-heating/non-coolong days.
All times are shown in hour ending Eastern Prevailing Time and historic peak values reflect current membership of the PJM RTO.

DRAFT

Table F-2

PJM RTO HISTORICAL NET ENERGY
(GWH)

YEAR	ENERGY	GROWTH RATE
1998	718,551	0.0%
1999	740,052	3.0%
2000	756,237	2.2%
2001	754,541	-0.2%
2002	782,300	3.7%
2003	780,693	-0.2%
2004	796,257	2.0%
2005	822,873	3.3%
2006	802,509	[illegible]
2007	835,782	[illegible]
2008	822,098	-1.6%
2009	780,693	-5.0%
2010	819,576	5.0%
2011	805,366	-1.7%
2012	791,219	-1.8%
2013	794,484	0.4%
2014	[illegible]519	0.1%

DRAFT

Note: All historic net energy values reflect the current membership of the PJM RTO.

Table G-1

ANNUALIZED AVERAGE GROWTH OF INDEXED ECONOMIC VARIABLE FOR EACH PJM ZONE AND RTO

	5-Year (2016-21)	10-Year (2016-26)	15-Year (2016-31)
AE	0.8%	0.7%	0.7%
BGE	1.3%	1.2%	1.2%
DPL	1.6%	1.4%	[illegible]
JCPL	1.2%	1.0%	[illegible]
METED	1.7%	1.5%	[illegible]5%
PECO	1.6%	1.4%	1.4%
PENLC	1.2%	1.1%	1.0%
PEPCO	1.6%	1.4%	1.3%
PL	1.6%	1.4%	1.3%
PS	1.2%	1.0%	[illegible]%
RECO	1.1%	[illegible]	[illegible]%
UGI	1.0%	0.8%	0.7%
AEP	1.8%	1.6%	1.5%
APS	1.8%	1.6%	1.5%
ATSI	1.5%	1.3%	1.2%
COMED	1.6%	[illegible]	[illegible]%
DAYTON	1.3%	[illegible]	[illegible]0%
DEOK	1.7%	1.5%	1.4%
DLCO	1.4%	[illegible]	1.2%
EKPC	1.8%	[illegible]6%	1.5%
DO[illegible]	[illegible]	1.5%	1.4%
[illegible]RTO	[illegible]%	[illegible]4%	1.3%

Source: Moody's Analytics, October, 2015

DRAFT

Notes:
Values presented are annualized compound average growth rates.
Indexed economic variable is a combination of U.S. Gross Domestic Product, Gross Metropolitan Product, Real Personal Income, Population, Households, and Non-Manufacturing Employment.

Table 15. Total Electricity Sales, Projected vs. Actual

Projected

(billion kilowatt-hours)

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
AEO 1994	2843	2891	2928	2962	3004	3039	3071	3112	3148	3185	3228	3263	3298	3332	3371	3406	3433	3469			
AEO 1995		2951	2987	2983	3026	3058	3085	3108	3134	3166	3204	3248	3285	3321	3357	3396	3433	3475			
AEO 1996			2973	2998	3039	3074	3106	3137	3173	3215	3282	3317	3363	3409	3454	3505	3553	3604	3660	3722	3775
AEO 1997				3075	3115	3168	3229	3290	3328	3379	3437	3497	3545	3596	3649	3697	3738	3784	3838	3899	3948
AEO 1998					3106	3204	3255	3318	3388	3438	3488	3546	3601	3658	3716	3775	3825	3877	3939	3996	4035
AEO 1999						3205	3262	3333	3402	3454	3492	3534	3585	3639	3691	3745	3793	3843	3900	3958	4005
AEO 2000							3288	3360	3402	3461	3523	3585	3647	3699	3753	3812	3861	3909	3958	4012	4059
AEO 2001								3384	3440	3530	3608	3681	3761	3838	3918	3998	4068	4147	4212	4288	4352
AEO 2002									3443	3502	3619	3711	3793	3869	3948	4022	4090	4170	4252	4332	4404
AEO 2003										3414	3527	3617	3684	3762	3848	3940	4014	4101	4183	4266	4336
AEO 2004											3495	3582	3669	3750	3830	3909	3977	4055	4133	4212	4285
AEO 2005												3547	3649	3722	3813	3912	3997	4070	4145	4220	4285
AEO 2006													3675	3700	3767	3847	3911	3978	4047	4118	4173
AEO 2007														3694	3757	3836	3891	3953	4014	4082	4138
AEO 2008															3744	3773	3807	3869	3927	3978	3979
AEO 2009																3725	3658	3737	3796	3847	3869
AEO 2010																	3589	3617	3728	3800	3809
AEO 2011																		3749	3692	3734	3770
AEO 2012																			3763	3729	3710
AEO 2013																				3712	3685
AEO 2014																					3686
Actual	2861	2935	3013	3101	3146	3264	3312	3421	3394	3465	3494	3547	3681	3670	3765	3733	3597	3754	3750	3695	3692
Average Absolute Difference	18	30	57	97	88	140	127	169	101	111	105	110	122	124	128	153	250	199	222	300	326

Projected vs. Actual

(percent difference)

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
AEO 1994	-0.6	-1.5	-2.8	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]			
AEO 1995		[illegible]	-1.5	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]			
AEO 1996			-4.3	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
AEO 1997				-0.8	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
AEO 1998					[illegible]	[illegible]	[illegible]	[illegible]	-0.2	[illegible]	-0.2	0.0	[illegible]	-0.3	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
AEO 1999						[illegible]	[illegible]	[illegible]	0.2	-0.3	-0.1	-0.4	[illegible]	[illegible]	[illegible]	0.3	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
AEO 2000							[illegible]	[illegible]	0.2	-0.1	[illegible]	[illegible]	-0.4	[illegible]	-0.3	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
AEO 2001								[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
AEO 2002									[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
AEO 2003										[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
AEO 2004											0.0	[illegible]	0.2	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
AEO 2005												0.0	-0.3	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
AEO 2006													0.4	[illegible]	0.1	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
AEO 2007														[illegible]	-0.2	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
AEO 2008														[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
AEO 2009																-0.2	[illegible]	-0.5	[illegible]	[illegible]	[illegible]
AEO 2010																	-0.2	[illegible]	[illegible]	[illegible]	[illegible]
AEO 2011																		-0.2	[illegible]	[illegible]	[illegible]
AEO 2012																			0.4	[illegible]	0.5
AEO 2013																				0.5	[illegible]
AEO 2014																					-0.1
Average Absolute Percent Difference	0.6	1.0	1.9	3.1	2.8	4.3	3.8	4.9	3.0	3.2	3.0	3.1	3.3	3.4	3.4	4.1	6.9	5.3	5.9	8.1	8.8

Sources: Projections: *Annual Energy Outlook*, Reference Case Projections, Various Editions.

Historical Data: U.S. Energy Information Administration, September 2014 Monthly Energy Review, DOE/EIA-0035(2013/08) (Washington, DC, September 25, 2014), Table 7.1.

PENGAD 800-631-6989
EXHIBIT
Companies
179

Renewable Resources and Wholesale Price Suppression

August 2013

Ohio | Public Utilities Commission

PENGAD 800-631-6989
EXHIBIT
Companies
180

INTRODUCTION

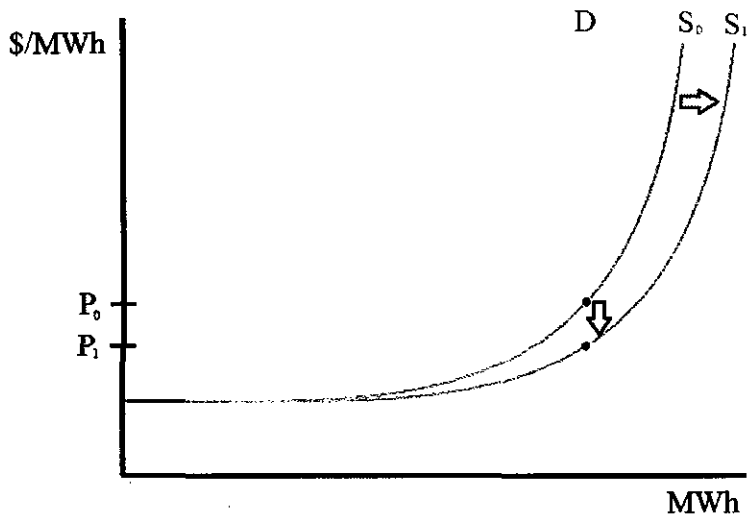
The study examines the relationship between renewable resource additions and wholesale *electricity markets in Ohio. The Staff of the Public Utilities Commission of Ohio has conducted* this study in an attempt to quantify the changes in *wholesale electricity prices* and *generator emissions* that are likely to occur as a result of the state's Alternative Energy Portfolio Standard (AEPS) requirements. Using the PROMOD IV production cost modeling software, Commission Staff is able to simulate electricity market outcomes and analyze the performance of the grid under various scenarios.

Two scenarios were developed for the purposes of this study. The first scenario considers only the utility-scale renewable resources that have been approved by the Ohio Power Siting Board *and* are currently operational. The second scenario considers all projects that have received a certificate of environmental compatibility and public need from the OPSB.

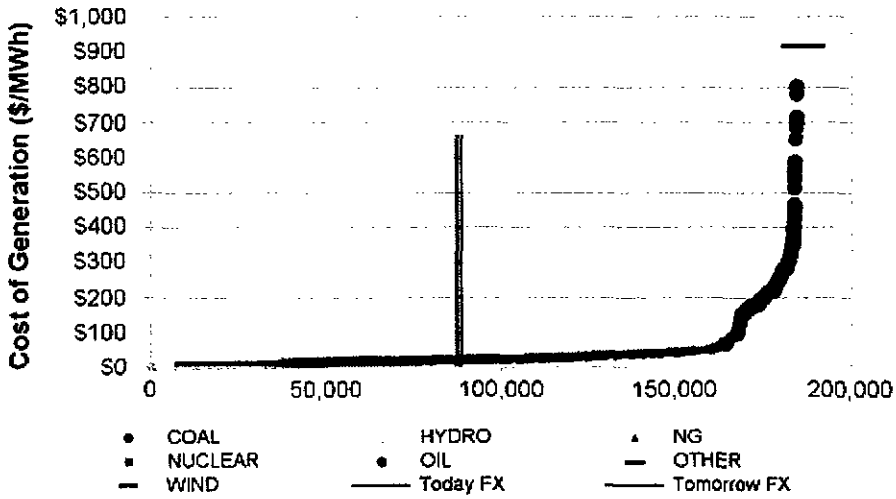
WHAT IS "PRICE SUPRESSION"?

Price suppression is a widely recognized phenomenon by which renewable resources produce lower wholesale market clearing prices. The economic theory that drives price suppression is actually quite simple. Renewable resources such as solar and wind are essentially zero marginal cost generators, as their "fuel" costs (sunlight and wind) are free. As such, they will always be dispatched first by the grid operator, thereby displacing units with higher operating costs. This results in lower wholesale market clearing prices than would have been experienced in the absence of the renewable resources.

A simple graphical representation appears below. The new renewable resources (depicted by the red line) are added to the dispatch stack, shifting the supply curve out and to the right. This results in a lower cost unit setting the market clearing price, shifting the equilibrium price down from P_0 to P_1.



For reference, an example of a real PJM dispatch curve appears below, with fuel types identified. Notice that Hydro, Nuclear, and Wind resources are all dispatched first on the supply stack.



source: Genscape

METHODOLOGY

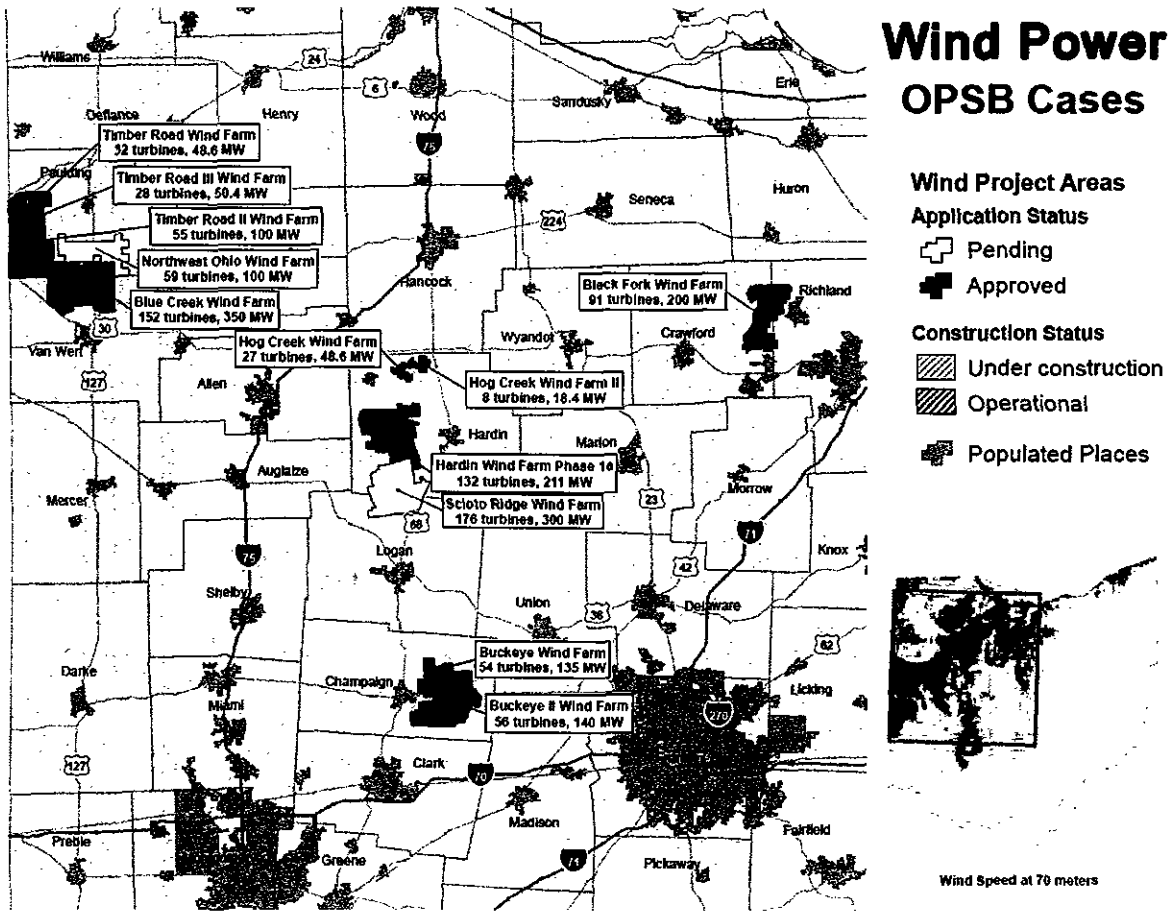
This analysis was performed with Ventyx's PROMOD IV electricity market modeling software. PROMOD IV is a detailed nodal market simulation tool that utilizes a security constrained unit commitment and dispatch algorithm to model generation, transmission, and market settlement across the Eastern Interconnection. The PROMOD IV software is one of the most powerful tools available to Commission Staff to analyze wholesale electricity markets and has been utilized by Staff and its consultants in various proceedings before the Commission.

Wholesale energy prices, known as locational marginal prices (LMPs), are calculated hourly for each transmission zone within Ohio and include generation, transmission congestion and loss components. To the extent that new renewable projects contribute to (or alleviate) transmission congestion or energy losses, these costs (or benefits) are captured by the model. For each scenario, total load costs are calculated using hourly price and load data and are aggregated to an annual value. This annual load cost is compared to a base case scenario in which no RPS mandate is in effect and therefore no utility-scale renewable projects are assumed to have been built in Ohio.

It is important to note that this study only attempts to quantify the price suppression effects that are associated with new utility-scale renewable projects and does not purport to comprise an overall cost-benefit analysis of these projects. While PROMOD IV is the industry standard in modeling production cost scenarios, it is not the proper tool to use when conducting least-cost capacity expansion analysis or integrated resource planning. To conduct such an analysis, it would be necessary to consider additional variables such as capital and capacity costs, renewable energy credit (REC) prices, and transmission upgrade expenses.

ASSUMPTIONS

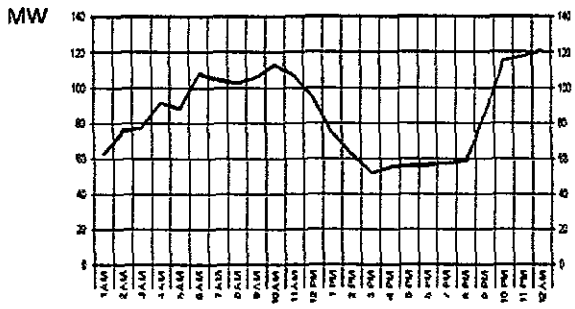
As described above, two scenarios are considered. The first scenario includes only the utility-scale renewable resources in Ohio that are approved and operational. The second scenario includes all projects that have received a certificate of environmental compatibility and public need from the OPSB, which includes some projects that are not yet operational. The results are then compared to a base case in which it is assumed that no utility-scale renewable resources are developed within Ohio. The projects associated with both scenarios are depicted in the map below, provided courtesy of the Ohio Power Siting Board.

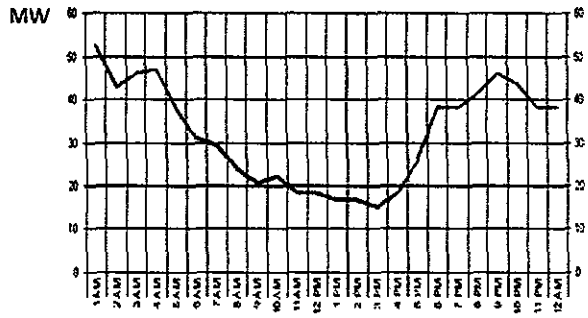


All simulations were modeled for calendar year 2014. Model input assumptions, such as hourly loads and fuel prices, are developed semi-annually by an independent third party. Staff did not make any adjustments to these assumptions.

Great care was taken to accurately incorporate new facilities into the powerflow model. Approved but not yet operational projects were modeled to conform to applications filed with the OPSB and to be consistent with generation interconnection requests submitted to PJM, the regional transmission organization.

Representative hourly profiles were included in the model to capture the intermittent nature of renewable generation. Capacity factors are based upon the geospatial coordinates of each project. For illustrative purposes, examples of these hourly output profiles appear below.





RESULTS – PRICE SUPPRESSION

The model demonstrates that wholesale electricity market prices in Ohio are reduced in both scenarios as a result of incorporating the renewable generation resources. Hourly LMPs are aggregated into a load-weighted average annual price in the tables below.

In the first scenario, which considers only those projects that are already operational, wholesale prices are reduced by approximately 0.15%.

	Load Weighted LMPs ($/MWh)				
	AEP	FirstEnergy	Dayton	Duke	Ohio
Base Case (no RPS)	$31.91	$32.42	$32.87	$32.22	$32.25
Scenario 1: Operational Facilities	$31.85	$32.37	$32.82	$32.18	$32.20
	-0.16%	-0.15%	-0.16%	-0.12%	-0.15%

In the second scenario, which considers all OPSB-approved projects, wholesale prices are reduced by approximately 0.51%, or just over one half of one percent.

	Load Weighted LMPs ($/MWh)				
	AEP	FirstEnergy	Dayton	Duke	Ohio
Base Case (no RPS)	$31.91	$32.42	$32.87	$32.22	$32.25
Scenario 2: Approved Facilities	$31.75	$32.25	$32.67	$32.07	$32.08
	-0.50%	-0.52%	-0.61%	-0.47%	-0.51%

The total load cost benefits that arise from lower wholesale clearing prices are calculated below for each utility transmission area and the state as a whole. For these savings to be ultimately realized by customers, one must assume that retail rates are themselves a function of wholesale prices, an assumption that is consistent with Ohio's transition towards a competitive model of generation procurement.

These benefits can be considered a partial offset to the costs incurred by utilities to comply with alternative energy mandates. According to data contained within the 2011 Alternative Energy Portfolio Standard Report to the General Assembly, Ohio investor owned utilities procured 518,992 Ohio non-solar renewable MWHs at an average price per REC of $110.55. The price suppression effect therefore offsets 14.7% of the cost of procuring in-state non-solar RECs for investor owned utilities in scenario 1, and 49.8% of the cost of in-state non-solar compliance in scenario 2.

Total Load Savings (2014)

	AEP	FirstEnergy	Dayton	Duke	Ohio
Scenario 1: Operational Facilities	$3,355,033	$3,213,389	$934,960	$926,272	$8,429,653
Scenario 2: Approved Facilities	$10,216,471	$11,114,557	$3,656,707	$3,605,089	$28,592,824

RESULTS: CARBON EMISSIONS

The model demonstrates that additional renewable generation resources in Ohio also reduce CO2 emissions. PROMOD IV does account for the fact that intermittent resources can cause traditional fossil-fired plants to be ramped up and down more frequently and therefore run less efficiently. However, this effect does not seem to significantly impede overall emission reductions. It is likely that this outcome is facilitated in part by the membership of Ohio utilities in the PJM regional transmission organization, which provides the centralized unit dispatch and flexibility required to avoid significant negative consequences for the efficiency of existing fossil-fired generators. The carbon dioxide emissions reductions for both scenarios are depicted below.

	CO2 Emissions (Metric Tons)	
Base Case (No RPS)	116,364,317	% Change
Scenario 1: Operational Facilities	116,162,271	-0.17%
Scenario 2: Approved Facilities	115,787,677	-0.50%

CONCLUSION

The model simulations indicate that, consistent with theoretical expectations, Ohioans are already benefiting from renewable resource additions through downward pressure on wholesale market prices and reduced emissions. No severe congestion issues or emergency curtailments were observed, even after incorporating all approved projects, which suggests that the electric grid in Ohio is sufficiently robust to support the continued development of utility-scale renewable projects. The modeling demonstrates that Ohio's Alternative Energy Portfolio Standard has already successfully reduced carbon dioxide emissions below a baseline level.

As renewable generation requirements escalate and new projects are required, future model runs can be made to assess the extent to which these outcomes persist. This analysis can be conducted by Commission Staff through PROMOD IV simulation, a powerful, well respected and unbiased tool that is currently at our disposal.

OMAEG EX. 26A

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan.	)	Case No. 14-1297-EL-SSO

CORRECTED
THIRD SUPPLEMENTAL TESTIMONY OF EDWARD W. HILL
ON BEHALF OF THE
OHIO MANUFACTURERS' ASSOCIATION ENERGY GROUP

December 30, 2015
As corrected, January 13, 2016

1 **Introduction, Purpose, and Summary of Conclusions**

2 **Q. Please state your name, title, and business address.**

3 A. My name is Edward W. Hill. I am Professor of Public Affairs and City and
4 Regional Planning and a member of the Faculty of the Discovery Theme in
5 Materials and Manufacturing for Sustainability at The Ohio State University's
6 John Glenn College of Public Affairs and College of Engineering. I was appointed
7 to this position beginning September 1, 2015. I retired as the Dean of the Maxine
8 Goodman Levin College of Urban Affairs at Cleveland State University and
9 Professor of Economic Development on June 30, 2015. My business address is
10 310P Page Hall, 1810 College Road, Columbus, Ohio 43210.

11

12 **Q. Please describe your educational background, professional qualifications,**
13 **and employment experience.**

14 A. I graduated from the University of Pennsylvania with a bachelor's degree in
15 economics and urban studies. I then attended the Massachusetts Institute of
16 Technology where I earned a master's degree in City and Regional Planning and
17 a Ph.D. in Economics and Regional Planning. My doctoral field examinations in
18 economics were in industrial organization and regulation, labor economics, and
19 urban and regional economics. In the Department of Urban Studies and Planning
20 my examinations were in regional economic development.

21 I was a member of the Cleveland State University faculty from 1985 to the end of
22 June 2015. During my 30 years at Cleveland State University I rose through the
23 academic ranks: Assistant Professor, Associate Professor, Professor and

1 Distinguished Scholar of Economic Development, Vice President of Economic
2 Development, and then serving as Dean of the Levin College of Urban Affairs.
3 The Ohio State University asked me to join the interdisciplinary Discovery
4 Theme in Materials and Manufacturing for a Sustainable World beginning in the
5 2015-16 academic year. I was appointed as a Professor in the John Glenn College
6 of Public Affairs and in City and Regional Planning and I am a faculty member of
7 the Ohio Manufacturing Institute. I am teaching the doctoral seminar in Public
8 Economics in the spring of 2016. I will be teaching economic development policy
9 and practice and public finance in subsequent semesters.
10 In addition, I was a non-resident Senior Fellow at the Brookings Institution's
11 Metropolitan Policy Program and was an Adjunct Professor in Public
12 Administration at South China University of Technology for three years. I was
13 also a non-resident Visiting Fellow at the Institute of Government Studies at the
14 University of California at Berkeley for five years, ending in 2013.
15 I was the inaugural chair of the National Institute of Standards and Technology's
16 Manufacturing Extension Partnership's National Advisory Board. I served in that
17 capacity from 2007 until 2010. I continued to serve on that Board until my term
18 statutorily expired in 2014.
19 I have also served on Ohio's Urban Revitalization Task Force (appointed by
20 Governor Taft), the Auto Industry Support Council (appointed by Governor
21 Strickland), the Cooperative Education Advisory Commission (appointed by
22 Speaker Batchelder), and the Manufacturing Task Force (appointed by Director
23 Schmenk).

My research has focused on the areas of urban and regional economic development policy, the operation of regional labor markets, and industry studies with an emphasis on manufacturing. My research has a particular emphasis on issues that are important to the state of Ohio's economy.

I am widely published. I have published one book and am in the process of completing my second. I have edited five books, written eight book-length reports, and have authored over 90 articles, book chapters, and columns. I was the editor of *Economic Development Quarterly* from 1994 to 2005. *Economic Development Quarterly* publishes peer-reviewed research that is relevant to the development and renewal of the American economy.

I participated in much of the energy research conducted at the Levin College either as an advisor or as an investigator. I led the research and writing of the publication titled *Ohio Utica Shale Gas Monitor* and was one of the authors of *An Analysis of the Economic Potential for Shale Gas Formations in Ohio* (February 2012).[1] I was also the co-chair of the advisory committee to the recently released three-part report on the natural gas resources in the state of Ohio.[2]

Q. Have you provided written testimony before in this proceeding?

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[1] See, e.g., Edward W. Hill, et al., "Ohio Utica Shale Gas Monitor" (January 10, 2014) at http://engagedscholarship.csuohio.edu/urban_facpub/1143/; Thomas, Andrew R., Iryna Lendel, Edward Hill, Douglas Southgate, and Robert Chase, "An Analysis of the Economic Potential for Shale Gas Formations in Ohio" (February 2012) at http://engagedscholarship.csuohio.edu/urban_facpub/453/

[2] See, e.g., Iryna Lendel et al., "Economics of Utica Shale: "Mapping the Opportunities for Shale in Ohio: Workforce Analysis." (September 2015) at http://engagedscholarship.csuohio.edu/urban_facpub/1330/; "Economics of Utica Shale: Supply Chain Analysis" (September 2015) at http://engagedscholarship.csuohio.edu/urban_facpub/1329/; "Mapping Opportunities for Shale Development in Ohio" (September 2015) at http://engagedscholarship.csuohio.edu/urban_facpub/1328/

1 A. Yes, I provided written Direct Testimony on December 22, 2014,[3] Supplemental
2 Testimony on May 11, 2015,[4] and Second Supplemental Testimony on August 10,
3 2015.[5] My testimony addressed the policy implications that I believe the Public
4 Utilities Commission of Ohio (Commission or PUCO) should consider regarding the
5 request of Ohio Edison Company (Ohio Edison), The Cleveland Electric Illuminating
6 Company (CEI), and The Toledo Edison Company (Toledo Edison) (collectively, the
7 Companies) for approval of an Economic Stability Program (Program), which
8 includes shifting the financial risk of operating generation plants onto their customers
9 through a rider and the utilization of a power purchase agreement (PPA) to subsidize
10 portions of the generation capacity owned by the Companies' affiliate, FirstEnergy
11 Solutions,[6] as well as the various stipulations filed.[7] I explained that the proposal,
12 adopted by the stipulations, shifts the risk of owning and operating generating
13 capacity to customers, including those customers who choose to shop and purchase
14 their generation from alternative suppliers or generators other than the Companies'
15 affiliate, FirstEnergy Solutions. I also addressed, in response to the Attorney
16 Examiner's Entries dated March 23, 2015 and May 1, 2015, whether and how the
17 Commission's factors set forth in the recent AEP Ohio Order regarding AEP's
18 electric security plan (ESP) and request for cost recovery associated with a PPA[8]

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[3] OMAEG Ex. 17.

[4] OMAEG Ex. 18.

[5] OMAEG Ex. 19.

[6] Companies Ex. 1.

[7] Companies Ex. 2 through 4.

[8] *In the Matter of the Application of Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to R.C. 4928.143, in the Form of an Electric Security Plan*, Case No. 13-2385-EL-SSO, et al., Opinion and Order at 25 (February 25, 2015) (AEP Ohio Order).

should be considered in evaluating the Companies' request for future cost recovery associated with a PPA.[9]

Q. What is the purpose of your Third Supplemental Testimony?

A. My Third Supplemental Testimony addresses the Third Supplemental Stipulation and Recommendation filed in this proceeding on December 1, 2015 (Third Supp. Stipulation), and explains how the Third Supp. Stipulation submitted by the Companies differs considerably from the Application that it filed on August 4, 2014, as amended by the three previously filed stipulations.[10] The Third Supp. Stipulation presents a new ESP (termed by the Companies as the "Stipulated ESP IV"[11]) while keeping its economic security plan for the power plants included in the PPA largely unchanged. The Third Supp. Stipulation is also purportedly supported by a number of signatory or non-opposing parties (collectively, Signatory Parties), which has also changed in substantial ways since the first stipulation was filed on December 22, 2014.[12] In the Third Supp. Stipulation, the Companies have raised new issues, offered new arguments, and presented an expanded coalition of supporters, labeled a "redistributive

[9] *In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to R.C. § 4928.143 in the Form of an Electric Security Plan*, Case No. 14-1297-EL-SSO (ESP IV Proceeding), Entry at 2 (March 23, 2015) and Entry at 10 (May 1, 2015) (citing AEP Ohio Order).

[10] As explained by the Third Supp. Stipulation at 2, the Third Supp. Stipulation, together with the "Prior Stipulations" (defined as the December 22, 2014 Stipulation, the May 28, 2015 Supplemental Stipulation, and the June 4, 2015 Second Supplemental Stipulation) form the "Stipulated ESP IV," which must be considered as a package. See also Fifth Supplemental Testimony of Eileen M. Mikkelsen at 2 (December 1, 2015) (Mikkelsen Fifth Supplemental Testimony). See OMAEG Ex. 19 for a discussion of the amendments to the Application as a result of the three Prior Stipulations.

[11] Id.

[12] Company Ex. 2 and 2A.

1 *coalition," in an attempt to influence the public policy process in ways that are*
2 deleterious for the state of Ohio. Also, the Third Supp. Stipulation and
3 supporting testimony presents an analysis of the Commission's three-pronged
4 *test used to evaluate regulatory settlements.*[13]
5 The Signatory Parties of the Third Supp. Stipulation and Stipulated ESP IV, with
6 the exception of the staff of the PUCO, constitute a redistributive coalition; they
7 are not a *representative cross-section of diverse interests* that *serve as a proxy*
8 for the public's interest in this case as is asserted in the Third Supp. Stipulation.
9 Rather, the Signatory Parties represent their own corporate and organizational
10 *interests.*
11
12 **Q. Does the Third Supp. Stipulation or Stipulated ESP IV satisfy all prongs of**
13 **the Commission's three-part test referenced by the Companies?**[14]
14 A. No. Neither the Third Supp. Stipulation nor the Stipulated ESP IV satisfies any
15 prong of the three-part test:
16 (a) The Signatory Parties do not "represent a variety of diverse interests." Instead,
17 they represent a somewhat diverse, *ad hoc*, collection of corporate and institutional
18 interests that benefit directly from specific aspects of the Third Supp. Stipulation or
19 the other stipulations comprising the Stipulated ESP IV. The Signatory Parties only
20 represent themselves and provide a façade of representational diversity. The
21 Signatory Parties did not bargain on behalf of large classes of customers or a diverse

[13]Third Supp. Stipulation at 4; (Mikkelsen Fifth Supplemental Testimony) at 7-10.
[14]Id. at 9-10.

group. They did not secure benefits for all individuals or businesses that were not direct participants in the bargaining, a particular type of participant, or members of organizations that participated in the bargaining. They sought benefits either for their own company or what amount to benefits for their members.

(b) The Stipulated ESP IV violates a number of important regulatory principles and practices. Specifically, the Stipulated ESP IV:

- Re-imposes an oligopoly in the electric generating market.
- Deters new entry into the electric generating market, thwarting both competition and hurting the long-term reliability of the electric power system as a whole in the state of Ohio.
- Introduces *de facto* price discrimination among competing large electricity users based solely on organizational membership or a particular type of customer.
- Relies upon an opaque system of income transfers and cross-subsidies among consumers.

(c) The Stipulated ESP IV as a whole does not benefit customers and the public interest. The major beneficiaries from the Stipulated ESP IV are FirstEnergy, its stockholders, and management. The Stipulated ESP IV shifts business risk away from stockholders and management to customers. The Stipulated ESP IV will result in regulatory taxation produced by two forms of subsidy. The first is through the Affiliate PPA and Rider RSS, where losses incurred in the operations of the plants covered by the PPA are passed on to all electricity users in the Companies' service territories. The second is through the way that negotiated rate discounts, subsidies,

1 and energy efficiency investments are made. Typically, the cost of utility negotiating
2 provisions in a regulatory setting are not borne by the utility, but instead, the amounts
3 spent are passed on to ratepayers that do not directly benefit. If you are a member of
4 the club that negotiated benefits to support the PPA politically, then you receive the
5 benefits of membership while others pay for the privilege.
6 The Stipulated ESP IV holds out the very real potential of deterring investment in
7 the electric generating capacity and harming the long-term reliability of the
8 electric system. The Stipulated ESP IV will reverse the benefits received by
9 consumers from deregulated markets for electric generation and will increase
10 electric rates relative to rates in competing regions and, thereby, harming the
11 economic prospects for businesses that are not members of the redistributive
12 coalition and of residents of the state of Ohio.
13
14 **Q. Have you had an opportunity to review the Third Supp. Stipulation?**
15 A. Yes. At various times I have reviewed all of the stipulations that have been filed to
16 date and together comprise the Stipulated ESP IV, as well as relevant portions of the
17 Companies' Plan termed at different times *Powering Ohio's Progress*, Electric
18 Security Plan IV, and ESP IV. In addition to reading the Third Supp. Stipulation, I
19 have also reviewed the supplemental testimony of Eileen Mikkelsen filed in this
20 proceeding on behalf of the Companies.[15]

[15] Supplemental Testimony of Eileen M. Mikkelsen (December 22, 2014) (Mikkelsen Supplemental Testimony or Company Ex. 8), Second Supplemental Testimony of Eileen M. Mikkelsen (May 4, 2015) (Mikkelsen Second Supplemental Testimony or Company Ex. 9), Third Supplemental Testimony of Eileen M. Mikkelsen (June 1, 2015) (Mikkelsen Third Supplemental Testimony or Company Ex. 10), Fourth Supplemental Testimony of Eileen M. Mikkelsen (June 4, 2015) (Mikkelsen Fourth Supplemental Testimony or Company Ex. 11), and Mikkelsen Fifth Supplemental Testimony.

1 **Q. What are the public benefits that are claimed in the Stipulated ESP IVresulting**
2 **from the Third Supp. Stipulation?**
3 A. There are six purported benefits presented in the testimony supporting the Stipulated
4 ESP IV resulting from the Third Supp. Stipulation: (1) Long-term, stable, and
5 predictable retail prices, (2) consumer empowerment and retail competition, (3)
6 economic development and job retention, (4) a business plan for transmission grid
7 modernization, (5) investments to begin modernizing the distribution system, and (6)
8 a mixture of alternative energy and carbon reduction actions.[16] I have listed these
9 purported benefits from the most misleading to the truly beneficial. To accept items 1
10 through 3 on their face requires suspending all knowledge of how markets operate
11 along with ignoring data that documents the economic benefits that competition in the
12 wholesale electric generating business has produced. My testimony is a response to
13 these six claims as they are justification for the Companies asserting that the PUCO's
14 three-prong test has been met by the Stipulated ESP IV.
15
16 **(1) LONG-TERM, STABLE AND PREDICTABLE RETAIL PRICES[17]**
17 **Q. Will long-term retail electric prices be more predictable and stable under the terms of**
18 **the Stipulated ESP IV?**
19 A. There are four components to an honest answer to this question: (i) the Companies'
20 affiliate's rate of return on equity on the PPA generating plants included in the Third
21 Supp. Stipulation will be both stable and predictable under the Stipulated ESP IV. (ii)
22 Retail electric prices may be somewhat more predictable under the Stipulated ESP IV

[16] Mikkelsen Fifth Supplemental Testimony at 10-12.

[17] Id. at 10, 13; Third Supp. Stipulation at 6.

than if the generating market remained unregulated. (iii) It is unlikely that retail electric prices will be more stable than they are currently. There are two reasons for this expectation. One is based on the documented 10-year record of stable electric prices that I will present. The other is based on the algebra of the Affiliate PPA. And, (iv) it is very likely that prices will be higher than if the generating market remain unregulated.

The Companies' Affiliate's Return on Equity:[18] The affiliate PPA has been the central, consistent, element through all proposals and submittals culminating in the Stipulated ESP IV. The Companies have testified that the two power plants in question, along with the Companies' partial ownership in OVEC lose money. What is new in the Third Supp. Stipulation is a reduction in the return on equity that FirstEnergy Solutions will receive (from 11.15% to 10.38%) from its equity invested in the plants covered by the affiliate PPA.[19] The period covered by the PPA, and its associated Rider RRS, has also been shortened from 16 years—2016 to 2031—to 8 years—2016 to 2024—in the Third Supp. Stipulation.[20] If approved this return on equity will be both stable and predictable.

Retail electric prices will be more predictable:[21] Retail electric prices may be somewhat more predictable under the affiliate PPA than under an unregulated

[18] Mikkelsen Fifth Supplemental Testimony at 7.

[19] Id. at 7 (which will be reflected in a modified Term Sheet regarding the PPA between the Compnaies and FirstEnergy Solutions).

[20] Id. at 3, 7 (which will be reflected in a modified Term Sheet regarding the PPA between the Compnaies and FirstEnergy Solutions).

[21] Id. at 10; Third Supp. Stipulation at 6.

generating market based on how the algebra of the PPA works. However, consumers will be negatively impacted by higher prices.

Under the structure of the affiliate PPA, the associated generating plants sell their power to the Companies at a price that covers the operating, or variable, costs associated with generating electricity, the cost of debt associated with the plant, and a 10.38% return on equity. Debt payments and the mandated return on equity are fixed costs—they do not vary substantially over time. The variable costs associated with producing power will change over time, with the cost of fuel being a large component.

If P_{PPA} represents the sales price to the Companies under the affiliate PPA, D the amortized debt payments, E the return on equity, VC the variable cost of producing electricity, and with ΔVC representing a one-unit change variable costs, then:

$$P_{PPA} = D + E + VC, \text{ then } \Delta PP_{PA} = \Delta VC.$$

If D and E change they do so at a very gradual rate and for purposes of this illustration they are essentially fixed. The only parts of the equation above that can vary are the variable costs associated with production. In terms of microeconomics, the marginal cost of operating the generating plants are only associated with changes in variable costs. However, in a competitive market, equilibrium prices are associated with marginal or variable costs, not total costs.

Will prices be more predictable then they are now as stated in the supporting testimony?[22] The answer is yes because predicting the fixed costs will be well known to both the Companies and the Commission, and, because making electricity is a capital intense business, fixed costs have a higher share of total costs then in other

[22] Id.

industries. The formulaic nature of fixed costs and their relatively large share of total costs, along with a guaranteed return on equity (profit) will improve the predictability of the retail electricity costs passed onto the Companies under the PPA (assuming no large capital investments are required), and then flowed through to customers per Rider RRS. This will be also create a more predictable revenue stream to FirstEnergy Solutions compared to the units selling directly into the grid where the generator can lose money.

Under the affiliate PPA, retail prices will still change, however, with changes in the variable costs associated with making electricity (i.e., necessary capital investments). The confusion comes from the fact that under the PPA retail prices will be more predictable than they are currently due to the large fixed cost component in the sales formula. However, retail electric prices will also be higher and will be as variable as they are now since variable costs drive the equilibrium price in a free market and in the PPA's formula.

If a two-dimensional graph were drawn of the cost curves under the PPA and under the current unregulated market, the slopes of the two curves will be the same, but the place where the cost curve intersects the y-axis (the axis that measures cost) will be higher for the PPA generating cost curve than it will be for the free market cost curve, as will every other point of the PPA cost curve. Both lines will be equally variable, but the PPA cost curve will be more slightly predictable.

The Companies want us to believe that predictability coupled with both higher prices than currently exist in today's free market and with the same level of variability is preferred by retail customers. I do not agree.

Retail electric prices will be more stable than they are currently:[23] Data collected by the Commission over the past 10 years is remarkable for two statistical facts. First, after adjusting for the electricity component in the consumer price index for all urban consumers electricity prices have been declining. The decline is most likely due to a combination of falling demand and the introduction of competitive electrical generating markets. The decline in demand is secular due to a combination of population loss, the profound negative impact of the Great Recession and the slow pace of recovery, greatly increased efficiency in the manufacturing sector, and then the opening of the vast natural gas resources in the Appalachian Basin—first in the Marcellus shale formation and then in the Utica formation—creating a cheap fuel source, especially when considering environmental compliance costs. Second, in statistical terms, prices have been stable around a downward trend. See Figures 1 to 5 included below.

Statistical stability means low levels of variation in the data, where variation means the spread of observations around the mean of the distribution. Two measures of variation are commonly used to describe dispersion in a data series: the standard deviation and the Coefficient of Variation (CV). The standard deviation is an absolute measure of the spread of distribution around its mean, or average. In a normal distribution approximately two-thirds of the observations will be clustered within plus or minus one standard deviation of the mean. The smaller the standard deviation the tighter is the spread of data around the mean. The CV is a relative measure that

[23] Mikkelsen Fifth Supp. Testimony at 9; Third Supp. Stipulation at 6.

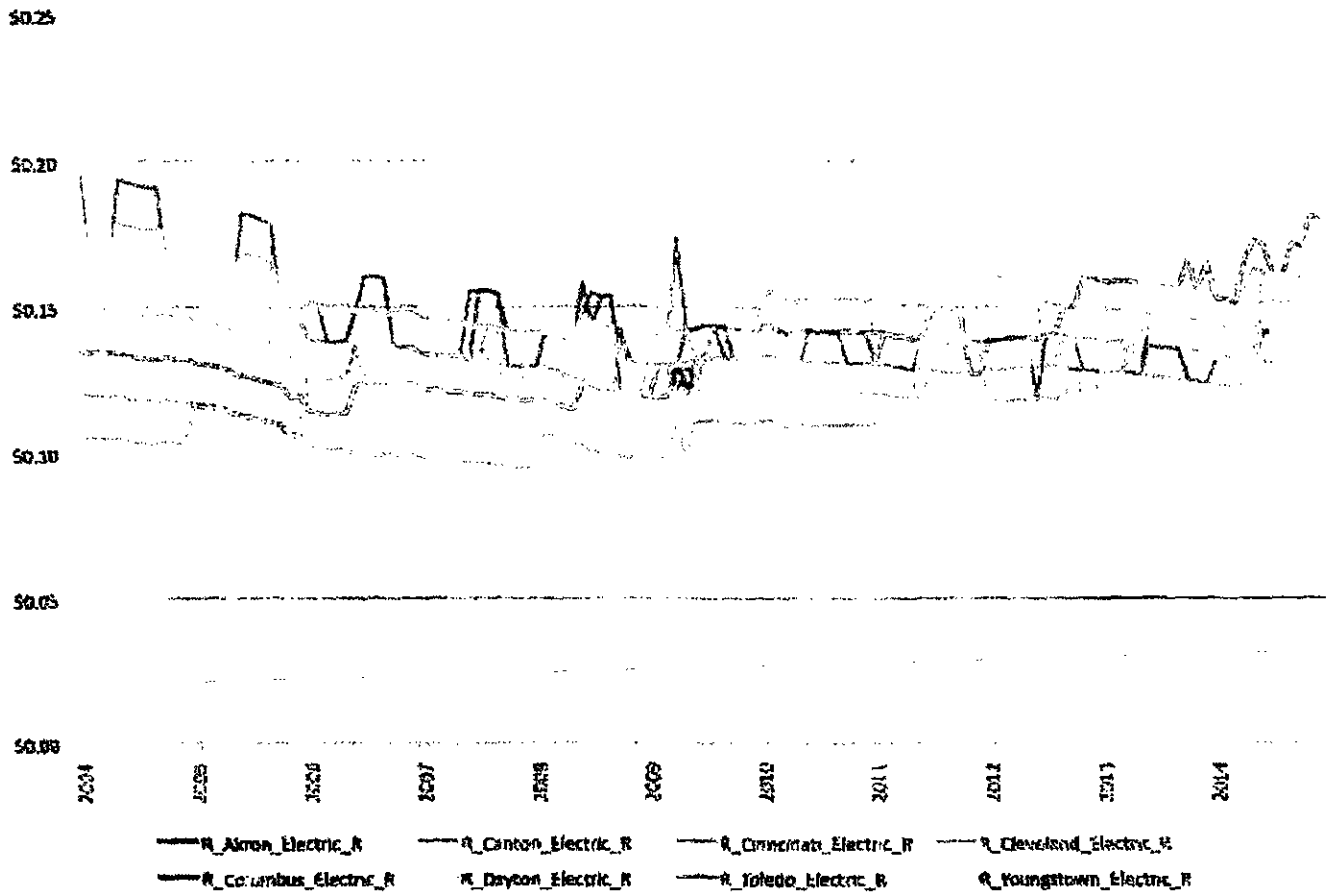
allows comparison of spread in different data series that are measured differently. The CV is defined as the standard deviation divided by the mean. See Table 1 included below.

The data displayed in Figures 1 to 5 below are from the monthly Ohio Utility Rate Survey, with the data covering January 2004 to December 2014. The staff of the Commission collects data monthly on the standard service offer (SSO) rates in the state's eight large metropolitan areas, Akron, Canton, Cincinnati, Cleveland, Columbus, Dayton, Toledo and Youngstown, based on prototypical usage. These data are in the figures below. Figure 1 is for residential electric SSO for 750 KWH of electricity; Figure 2 is for commercial electricity customers using 300,000 KWH monthly and 1,000 KWH daily; Figure 3 is for a major industrial customer using 6,000,000 KWH a month and 20,000 KWH daily. The data in Figures 1 to 3 are adjusted for inflation using the electricity component of CPI-U so that the data are presented in 2014 real dollars.

To illustrate the impact that the discovery of major natural gas resources in the Appalachian Basin has had on industrial energy prices, Figure 4 presents the data for commercial users of 45 MCF natural gas a month, while Figure 5 depicts the cost of a large industrial user of 350 MCF of natural gas. The data for Youngstown were incomplete in the dataset used to plot Figure 5.

Figure 1

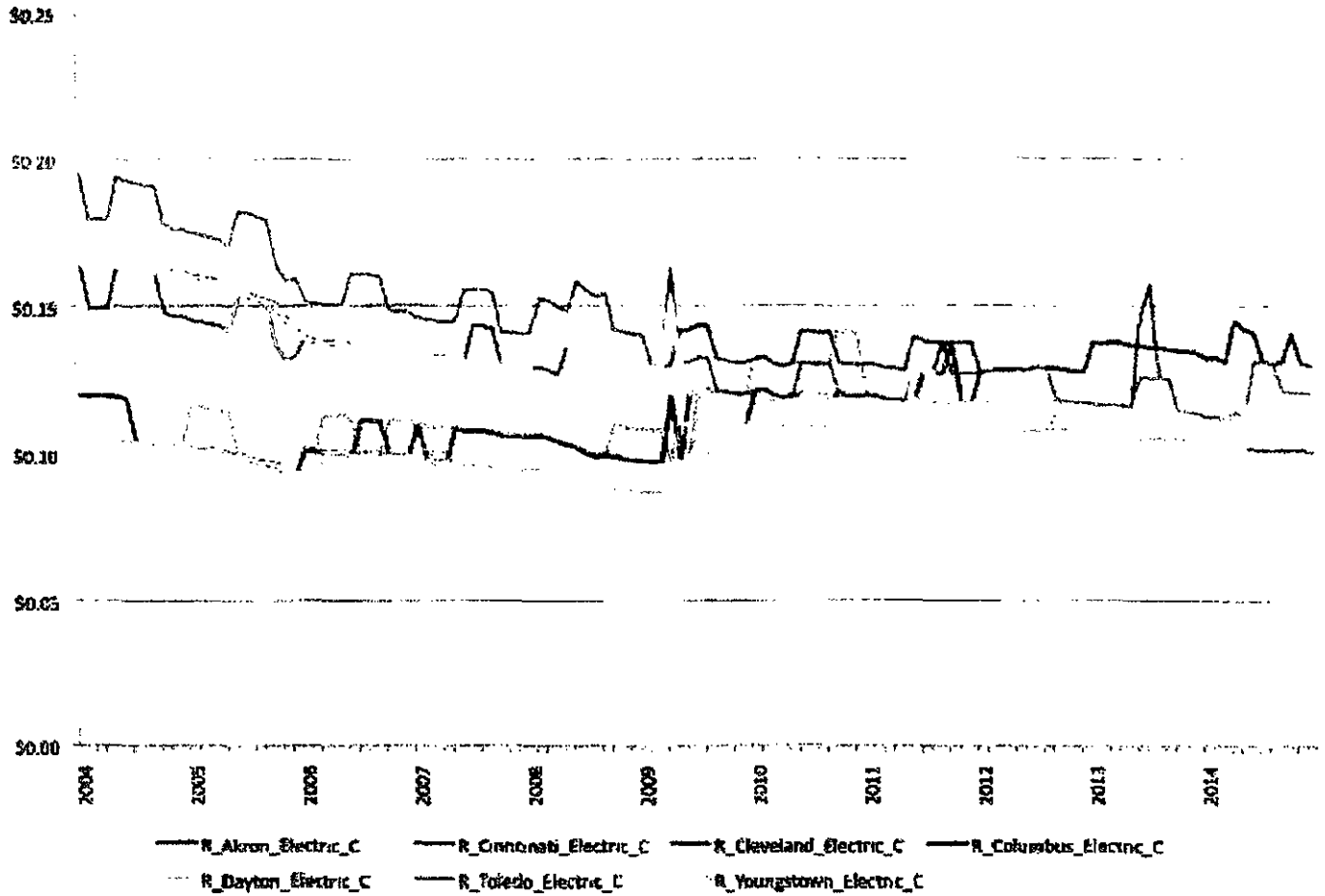
Inflation Adjusted Residential Standard Service Offer per KWH Based on a Standard Service Offer of 750KWH from January 2004 to December 2014



Sources: Public Utilities Commission of Ohio, Ohio Utility Rate Survey (monthly) and U.S. Bureau of Labor Statistics, Consumer Price Index—all Urban Consumers—Electricity, monthly downloaded from FRED, the data service of the St. Louis Federal Reserve Bank (December 29, 2015).

Figure 2

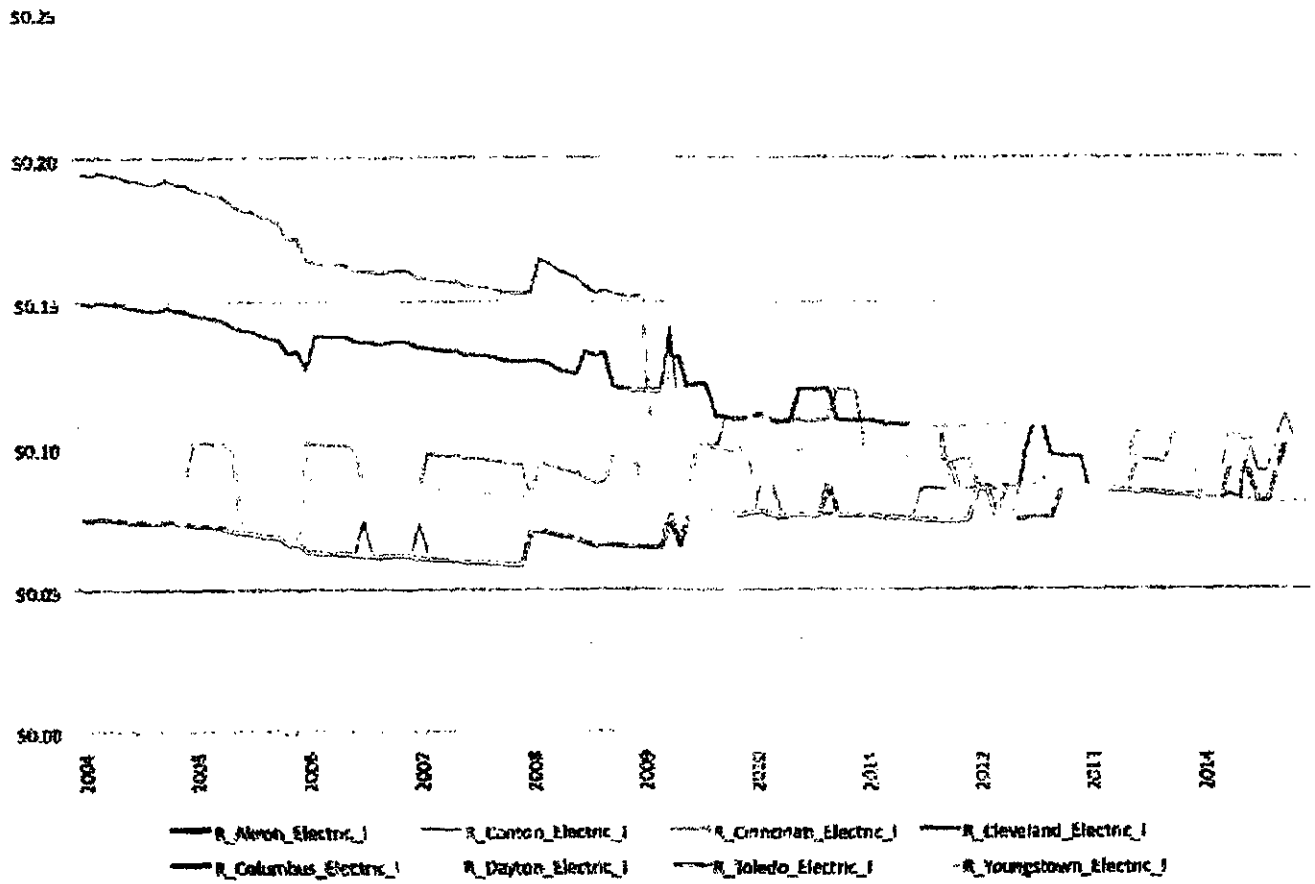
Inflation Adjusted Comparison of Commercial Utility Bills per KWH in 8 Major Ohio Cities Based on a Standard Service Offer of 300,000 KWH per Month and 1,000 KWH per Day from January 2004 to December 2014



Sources: See Figure 1

Figure 3

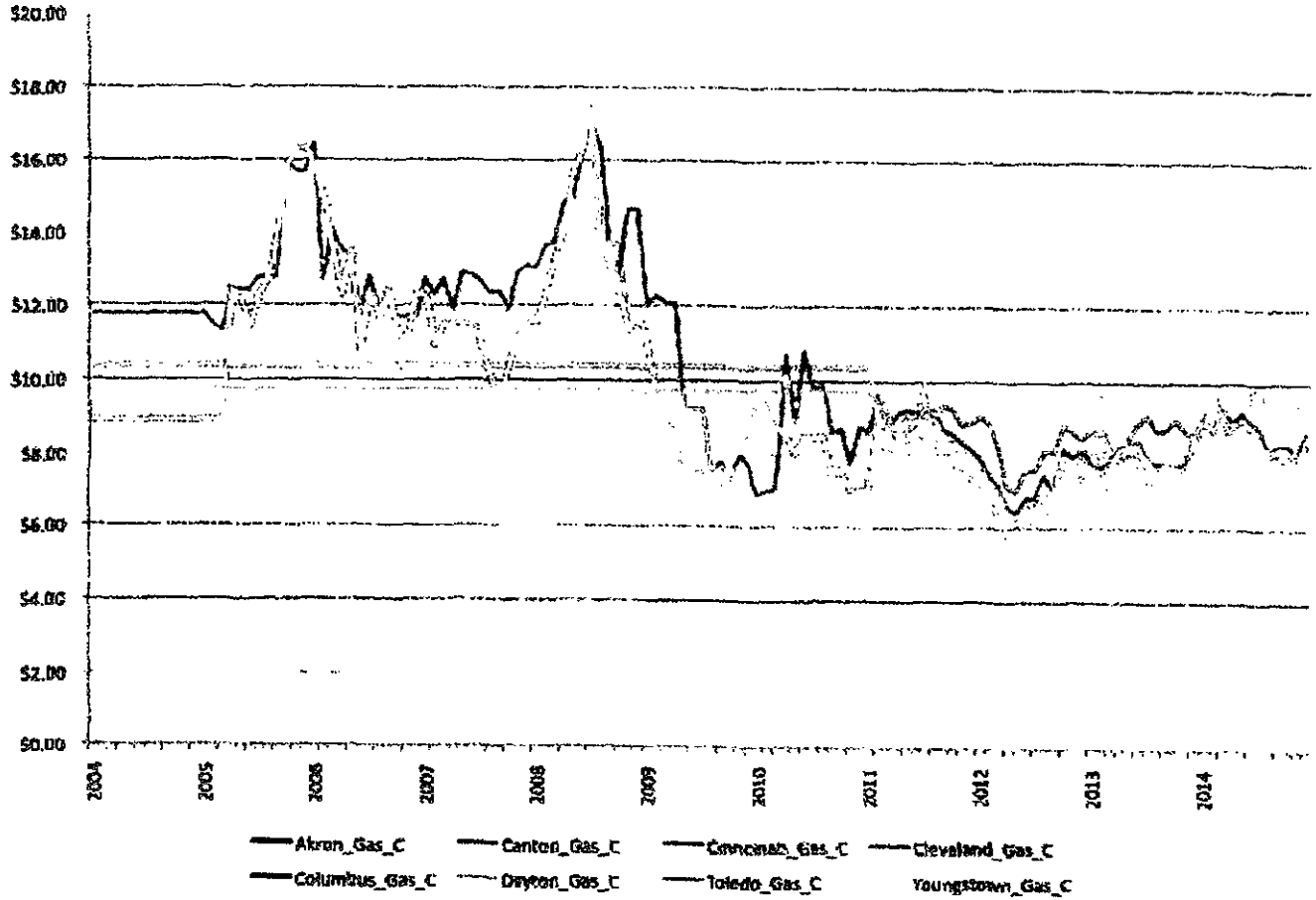
Inflation Adjusted Comparison of Industrial Utility Bills in 8 Major Ohio Cities per KWH Based on a Standard Service Offer of 6,000,000 KWH per Month and 20,000 KWH per Day from January 2004 to December 2014



Sources: See Figure 1

Figure 4

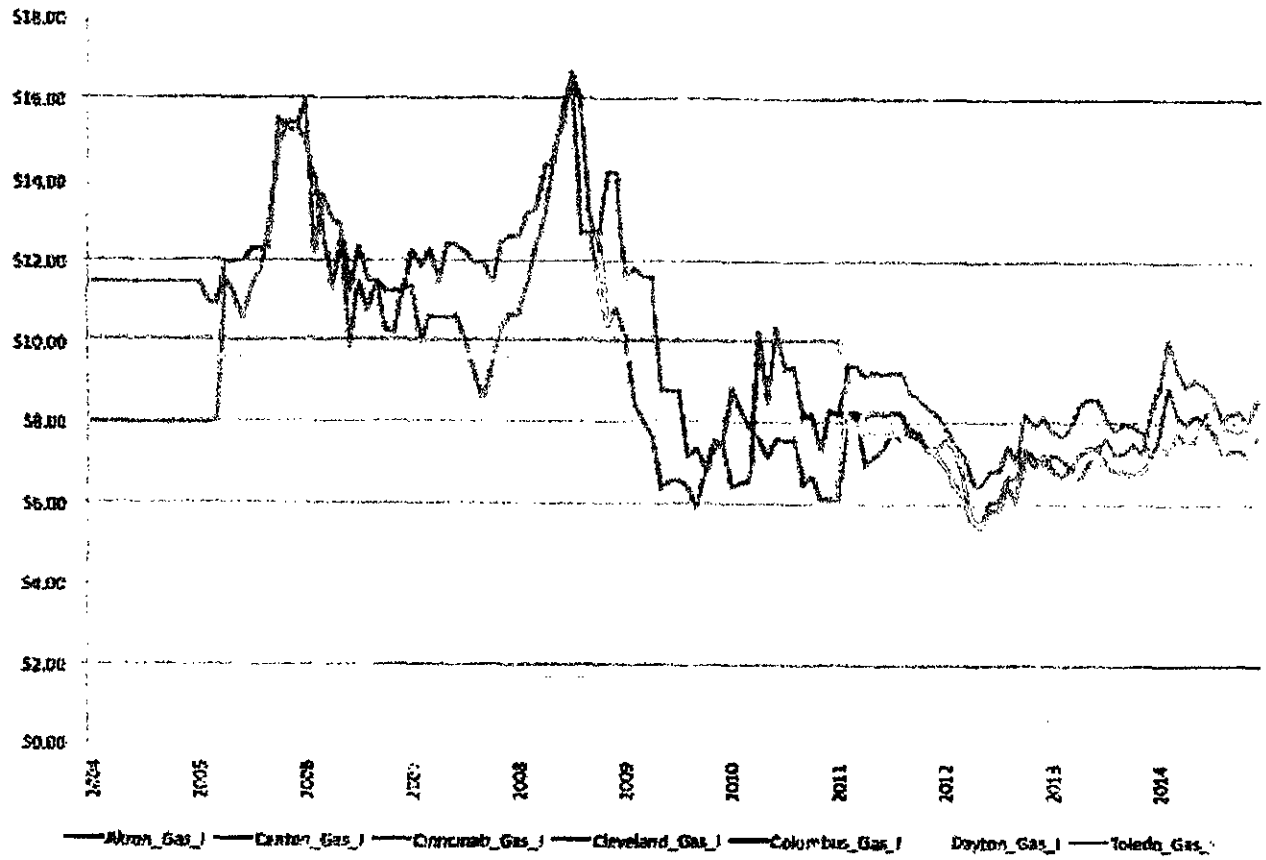
Comparison of Current Dollar Natural Gas Bills for Commercial Customers per MCF in 8 Ohio Cities with a Standard Service Offer on 46 MCF per Month from January 2004 to December 2014



Source: See Figure 1

Figure 5

Comparison of Current Dollar Natural Gas Bills of Industrial Customers per MCF in 8 Ohio Cities with a Standard Service Offer of 350 MCF per Month from January 2004 to December 2014



Source: See Figure 1

Table 1

Monthly Utility Rates Have Been Extremely Stable From 2004 to 2014. Variances Have Gotten Smaller

		Residential Electricity			Commercial Electricity			Industrial Electricity		
Years	Metropolitan Area	Standard Deviation	Average (Mean)	Coefficient of Variation	Standard Deviation	Average (Mean)	Coefficient of Variation	Standard Deviation	Average (Mean)	Coefficient of Variation
2004-2014	Akron	0.01	$0.14	0.10	0.02	$0.13	0.15	0.01	$0.10	0.14
	Canton	0.02	$0.12	0.16	0.02	$0.09	0.22	0.01	$0.08	0.17
	Cincinnati	0.01	$0.13	0.09	0.01	$0.11	0.09	0.01	$0.09	0.12
	Cleveland	0.02	$0.14	0.12	0.01	$0.13	0.09	0.02	$0.12	0.18
	Columbus	0.02	$0.14	0.12	0.01	$0.12	0.12	0.01	$0.07	0.12
	Dayton	0.01	$0.14	0.09	0.01	$0.10	0.10	0.01	$0.09	0.12
	Toledo	0.01	$0.14	0.09	0.02	$0.14	0.16	0.04	$0.13	0.32
	Youngstown	0.01	$0.14	0.10	0.02	$0.13	0.15	0.01	$0.10	0.14
Jan-04 to Dec-08	Akron	0.01	$0.15	0.08	0.01	$0.14	0.09	0.01	$0.11	0.09
	Canton	0.01	$0.10	0.06	0.00	$0.07	0.04	0.01	$0.07	0.08
	Cincinnati	0.01	$0.12	0.06	0.01	$0.11	0.05	0.01	$0.09	0.11
	Cleveland	0.02	$0.15	0.13	0.01	$0.14	0.07	0.01	$0.14	0.06
	Columbus	0.01	$0.12	0.05	0.01	$0.10	0.07	0.01	$0.07	0.08
	Dayton	0.01	$0.13	0.08	0.01	$0.10	0.05	0.00	$0.08	0.05
	Toledo	0.01	$0.15	0.09	0.02	$0.16	0.10	0.02	$0.17	0.09
	Youngstown	0.01	$0.15	0.08	0.01	$0.14	0.09	0.01	$0.11	0.09
Jan-09 to Dec-14	Akron	0.01	$0.13	0.07	0.01	$0.11	0.08	0.01	$0.09	0.10
	Canton	0.02	$0.13	0.14	0.02	$0.10	0.17	0.01	$0.09	0.13
	Cincinnati	0.01	$0.13	0.09	0.01	$0.11	0.10	0.01	$0.09	0.12
	Cleveland	0.01	$0.14	0.05	0.01	$0.13	0.08	0.01	$0.10	0.14
	Columbus	0.01	$0.15	0.10	0.01	$0.13	0.09	0.01	$0.08	0.09
	Dayton	0.01	$0.15	0.06	0.01	$0.11	0.08	0.01	$0.10	0.11
	Toledo	0.01	$0.14	0.06	0.01	$0.12	0.07	0.01	$0.09	0.13
	Youngstown	0.01	$0.13	0.07	0.01	$0.11	0.08	0.01	$0.09	0.10
Difference 04 to 08 and 09 to 14	Akron	0.00	-0.02	-0.01	0.00	-0.03	-0.01	0.00	-0.02	0.00
	Canton	0.01	0.03	0.08	0.01	0.03	0.12	0.01	0.02	0.05
	Cincinnati	0.00	0.01	0.03	0.01	0.01	0.05	0.00	0.00	0.02
	Cleveland	-0.01	-0.02	-0.08	0.00	-0.01	0.00	0.01	-0.04	0.08
	Columbus	0.01	0.02	0.05	0.00	0.02	0.02	0.00	0.01	0.01
	Dayton	0.00	0.02	-0.02	0.00	0.01	0.03	0.01	0.02	0.06
	Toledo	-0.01	-0.02	-0.04	-0.01	-0.04	-0.03	0.00	-0.08	0.04
	Youngstown	0.00	-0.02	-0.01	0.00	-0.03	-0.01	0.00	-0.02	0.00

Source: Calculated from Public Utilities Commission of Ohio, Ohio Utility Rate Survey, monthly.
http://www.puco.ohio.gov/puco/index.cfm/industry-information/statistical-reports/ohio-utility-rate-survey/#sthash.dL7uGQBs.dpbs

1 Real, inflation-adjusted, residential electricity prices have experienced 10-years of
2 secular decline with very modest price recovery beginning in mid-2009 (Figure 1)
3 across the state of Ohio. Since 2009, residential retail prices have gone up the most in
4 Canton and Akron regions, followed by Dayton, with the biggest real declines
5 occurring in the state's largest metropolitan areas. Because the data are for SSO rates,
6 it most likely overstates the rise in average monthly residential electric bills,
7 especially in Northeast Ohio. The downward trend in the cost of electricity to
8 commercial and industrial users is unmistakable in Figures 2 and 3, respectively.
9 Here, the Akron metropolitan area is the outlier with commercial bills increasing
10 from 2009 until they stabilized in late 2012 and Dayton's commercial users also saw
11 prices jump throughout 2009 before stabilizing. The other metropolitan areas
12 experienced consistent declines in commercial rates over the entire time period.
13 The industrial electricity market has converged over the decade. As the Figures
14 demonstrate, in 2004, there was a $0.12 per KWH spread in SSO rates in 2004 with a
15 high of nearly $0.20 per KWH in the Toledo region being the extreme outlier and
16 holding that position until 2009 when average SSO rates declined to the norm for the
17 state. Since 2012, the regional spread is about $0.03 per KWH.
18 The three Figures all show an overall pattern of decline in the cost of electricity
19 across the state's metropolitan areas with significant convergence in prices taking
20 place within each class for residential, commercial, and industrial customers
21 beginning in 2011. This is exactly the pattern an analyst expects to see in an operating
22 market. Nonetheless, if we review the statistics included in Table 1, we can see what
23 has occurred in terms of the spread and stability of rates across time.

Table 1 lists the standard deviation, mean, and CV by the eight metropolitan areas in the PUCO's data for each class of customers, residential, commercial, and industrial. The first block of rows provides this information for the full 10-year time period. The second block covers the first five-years, January 2004 to December 2008, and the third block covers the second five-year period, January 2009 to December 2014. Not only does the data break evenly into two five-year blocks, but early 2009 appears to be a break point in the data with a slight recovery in electric prices and an acceleration in the convergence in prices paid within each group of customers across the state's major metropolitan areas. In terms of electricity prices, early 2009 marked an important event—most likely associated with e recovery from the Great Recession. The second time period also marks the full realization of the benefits of deregulation of the electric generating markets.

The last block of rows in the table lists the differences between the values in the two time periods. The value for the 2004 to 2009 time period was subtracted from the value for the later period, 2009 to 2014. If the result is negative it means that the value from 2009 to 2014 is smaller than the previous time period. For example, the negative mean number for residential customers in Cleveland in this bottom block means that the average SSO residential electric bill dropped by $0.02 per KWH. Similarly, the negative mean for industrial customers shows that the average SSO industrial customer saw their electric bill drop by $0.08 a KWH.

The data in Table 1 reveal the following:

- Bills for industrial customers have converged. Mean bill rates were lower in the second time period than in the first and the standard deviations in most of

the regions are at 0.01; this is ± one cent per KWH. Deregulation is working for industrial operations.

- Commercial electricity users have also experienced lower bills in the second time period compared to the first in Akron, Cleveland, and Toledo. The largest increase was in Canton at $.03 per KWH. Spreads are narrow with the standard deviation being 0.01 in most of the metros in second time period, with the exception of Canton.
- Residential ratepayers experienced average monthly bills decrease in Akron, Cleveland, Toledo, and Youngstown. Canton had a mean increase of $0.03 per KWH, Columbus and Dayton increased by $0.02 per KWH, and Cincinnati increased by $0.01 per KWH.
- The distributions of monthly billing rates for all three groups of customers were very narrow across both time periods, but were generally smaller form 2009 to 2014. Again, deregulation appears to be working. Prices have become less volatile.

The data presented in this section show that the Signatory Parties to the Stipulated ESP IV resulting from the Third Supplemental Stipulation got it wrong on this count. Electricity prices haves become more stable and predictable as deregulation progressed. Reregulation cannot narrow the spreads further, except by increasing costs across the board.

1 **(2) CONSUMER EMPOWERMENT AND RETAIL COMPETITION**

2 The Third Supp. Stipulation and supporting testimony asserts that the Stipulated
3 ESP IV will empower customers and enhance retail competition.[24] This is an
4 assertion that was made in previous iterations of the Prior Stipulations and
5 supporting testimony and it suffers from the same logical and factual
6 shortcomings as it did in the earlier versions. Consumers can never be
7 empowered and retail competition can never be enhanced when regulatory
8 powers are being used to increase the base price of the product and when
9 regulation takes away the consumer's ability to choose a supplier. There is no
10 amount of technology or information that can repeal partial price-fixing.
11 Rider RRS is explicitly designed to socialize the losses from the three power
12 plants under the PPA. The losses experienced by the Companies when they
13 purchase power from the generating plants and then sell it into the grid at a
14 lower price through PJM will be spread across to all ratepayers in the
15 Companies' service territories (unless the ratepayer obtains an exemption from
16 the PUCO), even if the residential consumer or business purchases their power
17 from another supplier. This *de facto* tax imposed by regulation to support the
18 Companies' affiliates uneconomic power plants neither empowers customers
19 nor enhances retail competition. All that it does is increase the cost of electricity
20 and lower the incentive to shop for lower electric prices and choose a
21 competitive supplier. Rider RRS is a cross-subsidy.

[24] Mikkelsen Fifth Supplemental Testimony at 10-12; Third Supp. Stipulation at 6.

1 Any benefits that may be derived from deployment of smart meters included in
2 the Third Supp. Stipulation[25] cannot offset the losses that will be derived from
3 empowering a monopoly in the generating market.
4
5 **(3) ECONOMIC DEVELOPMENT AND JOB RETENTION[26]**
6 **Q. Does the Stipulated ESP IV constitute a major economic and job development**
7 **investment or set of policies?[27]**
8 A. As a package, the Stipulated ESP IV resulting from the Third Supp. Stipulation does
9 not constitute a major economic and job development investment or set of policies.
10 There is a mixture in what the proposed Stipulated ESP IV purports to do to support
11 economic development activities within the Companies' footprint. The Companies are
12 an active supporter of the economic development profession and take a leadership
13 position in regional economic development activities. And the cooperative reputation
14 of the Companies' economic development group is well known. Of course, the
15 Companies do benefit from attracting and expanding the number of electricity users in
16 their service territories. The Companies agree to spend $3 million "in shareholders
17 dollars" in each of the eight 12-month cycles covered by the agreement on energy
18 conservation, and economic and job development programs in the Third Supp.
19 Stipulation.[28]

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[25] Third Supp. Stipulation at 3, 9-10.

[26] Mikkelsen Fifth Supplemental Testimony at 9-10; Third Supp. Stipulation at 3, 6.

[27] Id.

[28] See Mikkelsen Fifth Supplemental Testimony at 6. The Companies also drape their actions to keep its uneconomic power plants open as economic development spending. See comments that I previously made on the Prior Stipulations, which explain the analytical inadequacies of the analysis performed on that count. See Hill Supplemental Testimony at 10-13 (May 11, 2015) (OMAEG Ex. 18).

1 When considered in its totality, the Stipulated ESP IV cannot be seriously considered
2 to be a source of economic development stimulus because its ultimate goal is to raise
3 electricity prices within the Companies' service territories as a way of making its three
4 loss-making power plants profitable. When the price of a major factor of production
5 increases operating costs will rise, with the increase in operating costs comes pressure
6 to increase product prices, and when product prices increase relative to competitors'
7 prices profits shrink, pressure to hold back wages increases, and jobs are lost. All other
8 parts of the Stipulated ESP IV are window dressing. The primary goal of the
9 Companies is to provide enough gain to the various members of its redistributive
10 coalition to obtain approval of the affiliate PPA and Rider RRS.
11
12 **Q. Do the provisions of the Stipulated ESP IV resulting from the Third Supp. Stipulation**
13 **improve the competitive standing of the state of Ohio in terms of private sector operating**
14 **costs and economic development as stated in the Stipulated ESP IV and supporting**
15 **testimony?**[29]
16 A. No. Despite the benefits derived in the marketplace from decreases in real electricity
17 rates to commercial and industrial customers, Ohio's rates remain above those available
18 in competitor states. Table 2 below provides data from the U.S. Energy Information
19 Agency on the competitive position of Ohio in the aggregate compared to states in the
20 upper Midwest that we compete with—Illinois, Indiana, Kentucky, Michigan, New York,
21 Pennsylvania, and West Virginia, and in the Southeast and Middle South—Alabama,
22 Georgia, North Carolina, South Carolina, and Tennessee.

[29] Mikkelsen Fifth Supplemental Testimony at 9-10; Third Supp. Stipulation at 3, 6.

1 Table 2 includes data on the average retail price of electricity in these selected states as of
2 2013. Ohio is ranked 23rd in the nation with an average price of $0.125 cents per KWH,
3 which corresponds with the data in Table 1. Kentucky, Indiana, and West Virginia all
4 have lower rates. Many of the Southeastern industrial states that Ohio competes with
5 regularly also have lower rates—Alabama, Georgia, North Carolina, and Tennessee. I am
6 using retail rates as a proxy for commercial and industrial rates, assuming that they are
7 highly correlated. If so, this is no time to be raising rates and discouraging new
8 investment through regulatory fiat.
9 Ohio is the 9th largest electricity generating state in the nation while we are the 7th largest
10 in terms of the amount of total energy used by our industrial sector, the 6th largest user of
11 energy in the commercial sector, and 7th largest in terms of total energy use in the
12 residential sector. Ohio is not a state that can be autarkic in terms of energy.[30] We are a
13 huge producer of energy, but we import energy as well. Increasing self-reliance in energy
14 requires a commitment on the part of the private sector to develop the natural gas
15 resources of the Appalachian Basin. This will require encouraging investment by new
16 entrants in gas fired power plants, which the Stipulated ESP IV does not.

[30]See Table 2 and Appendix Table 1 (attached hereto as Attachment EWH-1).

Table 2
Electricity Data for Ohio and Its Competitor States

State	Net Electricity Generation Sept.2015			Total Carbon Dioxide Emissions 2013			Average Retail Price Residential Electricity Sept. 2015			Total Energy Consumed per Capita, 2013		Total Energy Expenditures per Capita, 2013		Per Capita Energy Expenditure per Million Btu, 2013		
	National Rank	thousand MWh	Percent of U.S.	National Rank	million metric tons	Percent of U.S.	National Rank	cents/kWh	State:US Average	National Rank	million Btu	National Rank	Dollars	National Rank	Ratio Dollars: million Btu	State
Ohio	*9*	*11,033*	*3.1%*	*5*	*229*	*4.3%*	23	12.55	1.0	23	324	28	4,334	23	13.38	OH
Regional competitors																
Illinois	5	15,882	4.5%	4	230	4.4%	21	12.68	1.0	25	311	39	3,824	10	12.30	IL
Indiana	14	8,384	2.4%	7	200	3.8%	40	11.40	0.9	9	441	16	5,079	4	11.52	IN
Kentucky	20	6,724	1.9%	11	137	2.6%	47	10.36	0.8	11	414	15	5,097	11	12.31	KY
Michigan	13	9,044	2.6%	9	160	3.0%	13	14.56	1.1	32	287	36	4,107	34	14.31	MI
New York	7	12,005	3.4%	9	160	3.0%	6	18.44	1.4	50	184	51	3,350	44	18.21	NY
Pennsylvania	4	18,054	5.1%	3	244	4.6%	14	14.31	1.1	28	297	32	4,230	31	14.24	PA
West Virginia	23	6,013	1.7%	22	93	1.8%	44	10.79	0.8	14	398	19	4,794	7	12.05	WV
Southeastern competitors																
Alabama	6	12,993	3.7%	15	120	2.3%	26	12.31	0.9	13	400	18	4,997	12	12.49	AL
Georgia	10	10,663	3.0%	12	133	2.5%	30	12.10	0.9	34	280	37	4,004	33	14.30	GA
North Carolina	11	10,157	2.9%	14	122	2.3%	31	11.91	0.9	38	256	42	3,790	36	14.80	NC
South Carolina	15	8,220	2.3%	28	69	1.3%	19	12.76	1.0	19	333	23	4,553	26	13.67	SC
Tennessee	22	6,169	1.8%	20	97	1.8%	48	10.33	0.8	21	329	24	4,452	25	13.53	TN

Note: *All state ranks are from High (1) to Low (51)*

Source: U.S. Energy Information Agency, retrieved December 29, 2015, various tables.

1 **Q. Can economic development discounts and incentives provide benefits to all**
2 **ratepayers?**
3 A. If structured properly, yes. As I have explained previously, economic development
4 incentives can help companies lower production costs, control or provide increased
5 certainty over their operating costs, speed the opening of a plant, and influence the
6 design of plant and equipment[31]. Economic development incentives can be used to
7 bring fallow land into use and they can be used to provide a trained workforce. In
8 other words, a public benefit should be identifiable and the incentive should pass the
9 "but for" test—but for the incentive the operation would not have opened.
10 Incentives may be appropriate for economic development reasons, but the incentives
11 need to be uniformly applied and available to all similarly situated customers. The
12 criteria for qualifying for the incentives and discounts should not be so narrowly
13 tailored that they are discriminatory or only apply to one or a few companies.
14 Economic development incentives also should be restricted to companies that
15 primarily sell goods and services to out-of-state customers or have their goods and
16 services bundled into these exported goods and services. These firms are considered
17 to be part of the economic base of the state.
18 The selection of the recipients of narrowly defined economic development incentives
19 should not be made by a private company (e.g., the Companies) that is in a position to
20 provide one of its customers with a competitive advantage over another company in
21 its service territory. This is especially true if there is a *quid-pro-quo* as is the case in
22 the proceeding currently pending before the Commission. Most importantly, the state

[31] See OMAEG Ex. 19 at 10-11.

1 of Ohio should not be delegating its economic development strategy and authority to
2 a privately owned electric utility.
3 What is presented in the Stipulated ESP IV is not a set of economic development
4 incentives. Instead, the incentives are targeted price reductions and discounts that are
5 being offered by the Companies through the regulatory process to only those
6 customers or groups that have been invited to join the exclusive club formed by the
7 Companies, and the costs of such discounts and incentives are being largely passed on
8 to the broad pool of ratepayers in the Companies' service territories who were not
9 invited to join the club formed by the Companies. While incentives may reduce the
10 expenses and provide associated benefits to the Signatory Parties that are receiving
11 the incentive, such discounting becomes problematic when the cost of the incentive is
12 then passed on to other customers or other classes of customers rather than being
13 financially absorbed by the company.

14 **Q. Can the Stipulated ESP IV negatively affect interstate commerce and investment in**
15 **Ohio's electric generating infrastructure?**

16 A. The Energy Information Agency's profile of the state of Ohio shows that our state of
17 Ohio is the 9th largest generator of electricity in the nation, accounting for 3.1% of all
18 net electricity generated in 2012.[32] Additionally, other states that are members of PJM
19 or touch Ohio's borders are also major sources of electricity production:
20 Pennsylvania is 4th, Illinois 5th, New York 7th, Michigan 13th, Indiana 14th, New
21 Jersey 19th, Kentucky 20th, and West Virginia is 23rd. Ohio's power plants can disrupt
22 new investment in generating capacity across the grid if there is assurance that they

[32] See Appendix Table 2 (attached hereto as Attachment EWH-2).

1 have financial guarantees that will prevent them from exiting the market. Due to the
2 nature of the grid, a PPA in Ohio will affect decisions to investment in generating
3 capacity across PJM's grid.
4 The impact will be greater if there is capacity that cannot clear PJM's auctions, as is
5 currently the case. A likely interstate outcome from the broad adoption of PPAs
6 across Ohio is that other states will adopt them in much the same way that Ohio is
7 following West Virginia's example. Political pressure will build to protect generating
8 assets that cannot clear the PJM market due to the way the PPAs will influence the
9 dynamics of the interstate power market. Ohio's demand will be tied through the
10 PPAs to Ohio's plants, meaning that demand for out-of-state production capacity will
11 drop. This will result in less efficient Ohio plants staying in the market while
12 unsubsidized, more efficient, out-of-state generating will be forced to exit.
13 The federal interest in this dynamic can grow if the PPAs deter investment in new
14 capacity and the reliability of the entire grid weakens and if the new capacity would
15 result in lowering levels of carbon emissions across the grid. This is when Ohio's
16 political-economic problem in supporting non-competitive generating plants becomes
17 a national problem of pollution nonattainment and a barrier to interstate commerce.
18
19
20
21
22

1 **Q. Do the benefits proffered in the other areas, a business plan for transmission grid**
2 **modernization, investments to begin modernizing of the distribution system, and a**
3 **mixture of alternative energy and carbon reduction actions offset the weaknesses that**
4 **the affiliate PPA generate?**

5 A. While some of these offerings may be desirable, they add more cost, risk continues
6 to be shifted from the Companies to ratepayers and the benefits from competition in
7 the generating market will be lost

8 **Q. Does this conclude your testimony?**

9 A. Yes.

CERTIFICATE OF SERVICE

I hereby certify that a true and accurate copy of the foregoing was served upon the following parties via electronic mail on January 13, 2016.

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Summary: Testimony Corrected Third Supplemental Testimony of Edward W. Hill On Behalf Of The Ohio Manufacturers' Association Energy Group electronically filed by Debra A Gaunder on behalf of Ohio Manufacturers' Association Energy Group

AppendixTable 1
Energy Consumption By End Use Sector Ranked by State Total Consumption: 2013

	Residential Sector		Commercial Sector		Industrial Sector *		Transportation Sector		Total Consumption *	
Rank	State	Trillion Btu	State	Trillion Btu	State	Trillion Btu	State	Trillion Btu	State	Trillion Btu
1	Texas	1,685.9	Texas	1,609.9	Texas	6,574.8	Texas	3,073.5	Texas	12,944.1
2	California	1,480.0	California	1,483.8	Louisiana	2,562.0	California	2,907.8	California	7,684.1
3	Florida	1,168.3	New York	1,134.2	California	1,812.4	Florida	1,466.0	Florida	4,077.9
4	New York	1,072.1	Florida	968.2	Indiana	1,325.5	New York	1,042.8	Illinois	4,011.5
5	Illinois	1,011.9	Illinois	804.4	Pennsylvania	1,318.2	Illinois	950.4	Louisiana	3,835.0
6	Pennsylvania	930.0	Ohio	694.9	Illinois	1,244.7	Ohio	920.3	Pennsylvania	3,795.0
7	Ohio	914.3	Pennsylvania	630.8	Ohio	1,216.0	Pennsylvania	916.0	Ohio	3,745.4
8	Michigan	773.6	Virginia	612.1	Alabama	846.5	New Jersey	847.1	New York	3,625.3
9	North Carolina	692.1	Michigan	600.7	Georgia	753.3	Georgia	823.2	Indiana	2,900.0
10	Georgia	688.1	New Jersey	600.7	Iowa	747.3	Virginia	733.4	Michigan	2,843.2
11	Virginia	626.6	North Carolina	555.8	Michigan	735.8	Michigan	733.1	Georgia	2,795.4
12	New Jersey	599.4	Georgia	530.8	Kentucky	712.9	North Carolina	720.5	North Carolina	2,524.1
13	Indiana	569.6	Tennessee	428.0	Minnesota	636.3	Louisiana	660.2	Virginia	2,410.7
14	Missouri	538.3	Maryland	424.6	Oklahoma	587.8	Indiana	620.0	New Jersey	2,314.5
15	Tennessee	531.9	Missouri	411.2	Tennessee	579.8	Tennessee	596.2	Tennessee	2,135.9
16	Washington	494.9	Indiana	385.0	Wisconsin	577.6	Washington	593.0	Washington	2,039.3
17	Massachusetts	452.6	Washington	382.8	Washington	568.6	Missouri	542.3	Alabama	1,931.4
18	Wisconsin	445.1	Wisconsin	369.1	North Carolina	555.7	Alabama	469.5	Minnesota	1,859.8
19	Maryland	431.5	Minnesota	358.0	South Carolina	527.4	Arizona	459.8	Missouri	1,857.0
20	Minnesota	417.3	Arizona	346.2	Florida	475.4	Massachusetts	456.2	Kentucky	1,822.7
21	Arizona	398.1	Massachusetts	290.9	Virginia	438.6	Oklahoma	453.9	Wisconsin	1,804.0
22	Kentucky	385.2	Colorado	285.6	Kansas	429.5	South Carolina	452.9	Oklahoma	1,622.8
23	Colorado	367.1	Kentucky	284.4	Colorado	417.0	Minnesota	448.2	South Carolina	1,591.4
24	Alabama	358.5	Louisiana	269.1	Mississippi	402.2	Kentucky	440.2	Iowa	1,516.5
25	South Carolina	351.6	South Carolina	259.5	Arkansas	398.8	Maryland	430.9	Colorado	1,471.8
26	Louisiana	343.6	Oklahoma	258.1	New York	376.3	Wisconsin	412.2	Massachusetts	1,442.6
27	Oklahoma	323.0	Alabama	256.8	Nebraska	372.5	Colorado	402.2	Arizona	1,414.8
28	Oregon	258.1	Iowa	215.7	Missouri	365.2	Mississippi	368.1	Maryland	1,403.8
29	Iowa	253.7	Kansas	210.1	Alaska	324.3	Oregon	301.3	Kansas	1,163.1
30	Connecticut	249.1	Oregon	190.9	Wyoming	309.2	Iowa	299.7	Mississippi	1,141.8
31	Arkansas	241.3	Connecticut	189.2	North Dakota	290.1	Kansas	287.3	Arkansas	1,093.0
32	Kansas	236.1	Arkansas	176.6	West Virginia	281.2	Arkansas	276.3	Oregon	996.7
33	Mississippi	211.2	Utah	163.5	New Jersey	267.3	Utah	250.0	Nebraska	871.8
34	Utah	175.3	Mississippi	160.3	Oregon	246.4	Connecticut	228.0	Utah	830.6
35	West Virginia	174.1	Nebraska	140.4	Massachusetts	242.8	Nevada	207.6	Connecticut	748.1
36	Nebraska	163.8	New Mexico	125.8	Utah	241.8	New Mexico	201.5	West Virginia	737.8
37	Nevada	162.1	Nevada	121.3	New Mexico	237.4	Nebraska	195.1	New Mexico	688.5
38	Idaho	127.3	West Virginia	112.3	Arizona	210.7	Alaska	172.8	Nevada	657.1
39	New Mexico	123.9	DC	111.3	Idaho	179.6	West Virginia	170.2	Alaska	609.0
40	New Hampshire	92.8	Idaho	88.1	Nevada	166.1	Hawaii	141.2	North Dakota	588.6
41	Maine	85.6	North Dakota	85.4	South Dakota	156.3	North Dakota	139.6	Wyoming	535.5
42	Montana	85.2	Montana	76.9	Maine	134.6	Idaho	134.6	Idaho	529.5
43	South Dakota	73.5	New Hampshire	70.4	Montana	121.0	Maine	128.0	Maine	407.1
44	North Dakota	73.4	South Dakota	65.2	Maryland	116.8	Montana	118.1	Montana	401.2
45	Rhode Island	66.2	Wyoming	63.1	Delaware	90.5	Wyoming	114.0	South Dakota	390.4
46	Delaware	65.4	Alaska	63.0	Connecticut	81.9	New Hampshire	99.4	New Hampshire	302.8
47	Wyoming	49.2	Maine	58.9	Hawaii	61.2	South Dakota	95.4	Hawaii	277.1
48	Alaska	48.9	Delaware	56.6	New Hampshire	40.1	Delaware	62.0	Delaware	274.5
49	Vermont	42.7	Rhode Island	49.0	Rhode Island	20.0	Rhode Island	58.3	Rhode Island	193.6
50	DC	37.0	Hawaii	39.0	Vermont	15.8	Vermont	49.2	DC	170.9
51	Hawaii	35.7	Vermont	26.0	DC	2.9	DC	19.8	Vermont	133.6
	United States	21,182.0	United States	17,894.3	United States	31,378.9	United States	26,689.4	United States	97,144.7

* Estimates for the United States include -17.4 trillion Btu of net imports of coal coke that is not allocated to the states.

Source: U.S. Energy Information Administration - EIA - Independent Statistics and Analysis

Table C10. Energy Consumption Estimates by End-Use Sector, Ranked by State, 2013

Retrieved from: https://www.eia.gov/state/seds/data.cfm?incfile=/state/seds/sep_sum/html/rank_use.html&sid=US

Retrieved on December 29, 2015

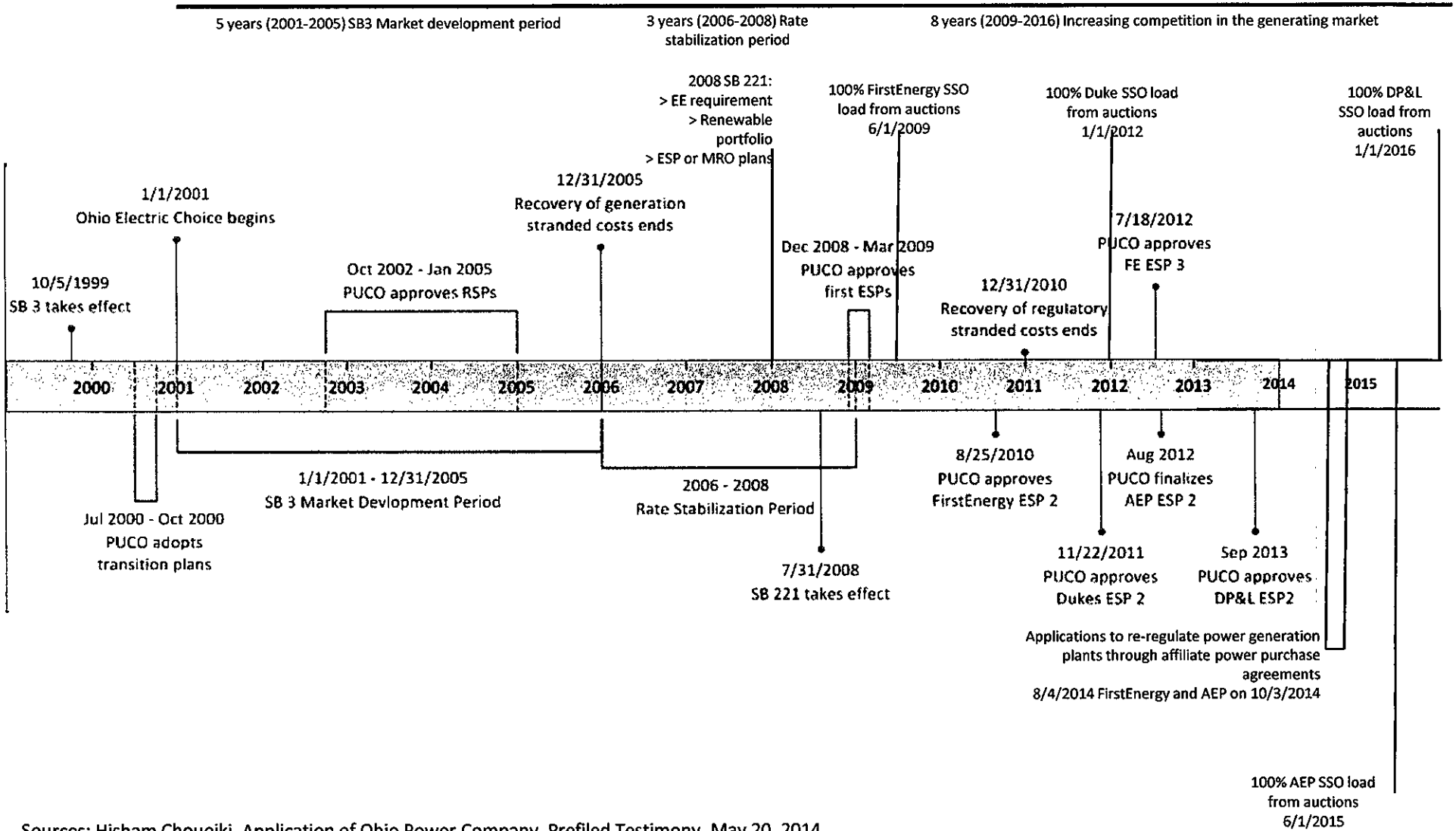
Appendix Table 2
Electricity and Energy Data by State

	Net Electricity Generation Sept.2015			Total Carbon Dioxide Emissions 2013			Average Retail Price Residential Electricity Sept. 2015			Total Energy Consumed per Capita, 2013		Total Energy Expenditures per Capita, 2013		Per Capita Energy Expenditure per Million Btu, 2013		
State	Rank	thousand MWh	Percent of U.S.	Rank	million metric tons	Percent of U.S.	Rank	cents/kWh	State:US Average	Rank	million Btu	Rank	Dollars	Rank	Ratio Dollars: million Btu	State
AK	49	450	0.1%	39	36	0.7%	3	20.61	1.6	3	826	2	9,596	5	11.62	AK
AL	6	12,993	3.7%	15	120	2.3%	26	12.31	0.9	13	400	18	4,997	12	12.49	AL
AR	27	4,822	1.4%	29	68	1.3%	46	10.52	0.8	17	369	20	4,732	14	12.82	AR
AZ	8	11,269	3.2%	21	94	1.8%	20	12.74	1.0	44	213	48	3,434	39	16.12	AZ
CA	3	19,164	5.5%	2	353	6.7%	7	18.38	1.4	48	200	47	3,563	43	17.82	CA
CO	30	4,445	1.3%	23	91	1.7%	24	12.43	1.0	35	279	44	3,737	24	13.39	CO
CT	36	3,160	0.9%	41	34	0.6%	4	19.23	1.5	46	208	31	4,260	49	20.48	CT
DC	51	0	0.0%	51	3	0.1%	22	12.65	1.0	36	263	49	3,378	15	12.84	DC
DE	47	785	0.2%	48	13	0.2%	16	13.65	1.0	28	297	33	4,165	30	14.02	DE
FL	2	21,039	6.0%	6	218	4.1%	33	11.81	0.9	46	208	50	3,375	40	16.23	FL
GA	10	10,663	3.0%	12	133	2.5%	30	12.1	0.9	34	280	37	4,004	33	14.30	GA
HI	46	879	0.3%	43	18	0.3%	1	28.52	2.2	49	197	11	5,350	51	27.16	HI
IA	29	4,657	1.3%	25	80	1.5%	28	12.26	0.9	5	490	7	5,583	3	11.39	IA
ID	43	1,182	0.3%	44	17	0.3%	49	10.08	0.8	22	328	29	4,317	19	13.16	ID
IL	5	15,882	4.5%	4	230	4.4%	21	12.68	1.0	25	311	39	3,824	10	12.30	IL
IN	14	8,384	2.4%	7	200	3.8%	40	11.4	0.9	9	441	16	5,079	4	11.52	IN
KS	31	4,202	1.2%	26	73	1.4%	28	12.26	0.9	12	402	13	5,267	18	13.10	KS
KY	20	6,724	1.9%	11	137	2.6%	47	10.36	0.8	11	414	15	5,097	11	12.31	KY
LA	12	9,440	2.7%	8	195	3.7%	50	9.61	0.7	2	828	4	8,545	2	10.32	LA
MA	37	2,998	0.9%	32	65	1.2%	5	18.83	1.4	43	215	34	4,149	46	19.30	MA
MD	39	2,946	0.8%	34	58	1.1%	15	14.1	1.1	40	236	38	3,868	41	16.39	MD
ME	45	893	0.3%	45	16	0.3%	11	15.6	1.2	27	306	6	5,606	45	18.32	ME
MI	13	9,044	2.6%	9	160	3.0%	13	14.56	1.1	32	287	36	4,107	34	14.31	MI
MN	26	4,849	1.4%	24	89	1.7%	17	12.86	1.0	18	343	22	4,554	21	13.28	MN
MO	18	7,154	2.0%	13	131	2.5%	37	11.46	0.9	26	307	25	4,421	35	14.40	MO
MS	25	5,228	1.5%	33	60	1.1%	42	11.07	0.8	16	382	12	5,268	28	13.79	MS
MT	41	2,301	0.7%	42	32	0.6%	38	11.43	0.9	15	395	10	5,452	29	13.80	MT
NC	11	10,157	2.9%	14	122	2.3%	31	11.91	0.9	38	256	42	3,790	36	14.80	NC
ND	38	2,957	0.8%	35	57	1.1%	41	11.11	0.9	4	813	1	####	16	12.96	ND
NE	35	3,416	1.0%	37	53	1.0%	27	12.29	0.9	7	466	9	5,508	6	11.82	NE
NH	42	1,628	0.5%	47	14	0.3%	9	17.25	1.3	42	229	21	4,600	47	20.09	NH
NJ	19	7,008	2.0%	16	105	2.0%	10	15.99	1.2	37	260	26	4,404	42	16.94	NJ
NM	40	2,683	0.8%	36	54	1.0%	18	12.78	1.0	20	330	27	4,387	22	13.29	NM
NV	34	3,610	1.0%	39	36	0.7%	25	12.39	0.9	41	235	46	3,646	38	15.51	NV
NY	7	12,005	3.4%	9	160	3.0%	6	18.44	1.4	50	184	51	3,350	44	18.21	NY
OH	9	11,033	3.1%	5	229	4.3%	23	12.55	1.0	23	324	28	4,334	23	13.38	OH
OK	21	6,274	1.8%	17	103	2.0%	45	10.57	0.8	10	421	17	5,073	8	12.05	OK
OR	28	4,739	1.4%	38	38	0.7%	43	10.88	0.8	39	254	43	3,788	37	14.91	OR
PA	4	18,054	5.1%	3	244	4.6%	14	14.31	1.1	28	297	32	4,230	31	14.24	PA
RI	48	495	0.1%	49	10	0.2%	2	21.61	1.7	50	184	45	3,715	48	20.19	RI
SC	15	8,220	2.3%	28	69	1.3%	19	12.76	1.0	19	333	23	4,553	26	13.67	SC
SD	44	920	0.3%	46	15	0.3%	34	11.8	0.9	8	462	8	5,569	9	12.05	SD
TN	22	6,169	1.8%	20	97	1.8%	48	10.33	0.8	21	329	24	4,452	25	13.53	TN
TX	1	41,300	11.8%	1	641	12.1%	35	11.65	0.9	6	488	5	6,114	13	12.53	TX
UT	33	3,685	1.0%	31	66	1.3%	39	11.42	0.9	33	286	41	3,791	20	13.26	UT
VA	17	7,361	2.1%	17	103	2.0%	32	11.85	0.9	31	291	35	4,145	32	14.24	VA
VT	50	125	0.0%	50	6	0.1%	8	17.27	1.3	44	213	14	5,196	50	24.39	VT
WA	16	7,966	2.3%	26	73	1.4%	51	9.36	0.7	30	292	40	3,801	17	13.02	WA
WI	24	5,772	1.6%	19	100	1.9%	12	14.82	1.1	24	314	30	4,304	27	13.71	WI
WV	23	6,013	1.7%	22	93	1.8%	44	10.79	0.8	14	398	19	4,794	7	12.05	WV
WY	32	3,835	1.1%	29	68	1.3%	36	11.49	0.9	1	918	3	9,358	1	10.19	WY
US		350,978	100.0%		5,280	100.0%		13.06	1.0							

Source: https://www.eia.gov/state/rankings/#/series/51

Data retrieved on December 28, 2015

A timeline of Ohio's electric restructuring



Sources: Hisham Choueiki, Application of Ohio Power Company, Prefiled Testimony, May 20, 2014
Application of Ohio Edison Company, et al. Prefiled Testimony, September 18, 2015
History of Regulation in Ohio, National Association of Regulatory Utility Commissioners, June 19, 2014.

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Projected vs. Actual
(percent difference)

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
AEO 1994	-0.6	-1.3	-2.8	-4.3	-4.8	-8.5	-7.3	-9.0	-7.3	-8.1	-7.8	-8.0	-9.0	-9.2	-10.3	-8.6	-4.6	-7.6			
AEO 1995			-1.5	-3.6	-3.6	-3.3	-6.0	-4.2	-1.1	-4.0	-4.1	-4.1	-10.3	-4.5	-10.8	-9.0	-4.9	-7.4			
AEO 1996				-3.3	-3.7	-6.1	-6.2	-4.5	-5.0	-1.2	-3.0	-3.5	-6.0	-7.1	-6.4	-8.1	-1.2	-4.0	-2.4		
AEO 1997					-1.0	-2.9	-2.5	-3.4	-2.0	-2.5	-1.6	-4.4	-1.5	-3.0	-0.1	-1.0					
AEO 1998						-1.3	-1.0	-1.7	-3.0	-0.2	-0.8	-0.2	0.0	-1.0	-0.3	-1.3					
AEO 1999							-1.4	-1.5	-2.6	0.2	-0.3	-0.1	-0.4	-2.3	-0.1	-3.0	0.3				
AEO 2000								-0.3	-1.8	0.2	-0.1			-0.4		-0.3					
AEO 2001									-1.7												
AEO 2002																					
AEO 2003										-1.5											
AEO 2004											0.0		0.2								
AEO 2005												0.0	-0.3								
AEO 2006													0.4		0.1						
AEO 2007															-0.2						
AEO 2008															-0.7						
AEO 2009																-0.2		-0.5			
AEO 2010																	-0.2	-3.5	-0.6		
AEO 2011																		-0.2	-1.8		
AEO 2012																			0.4		0.5
AEO 2013																				0.5	-0.7
AEO 2014																					-0.1
Average Absolute Percent Difference	0.6	1.0	1.9	3.1	2.6	4.3	3.8	4.9	3.0	3.2	3.0	3.1	3.3	3.4	3.4	4.1	6.9	5.3	5.9	8.1	8.8

Sources: Projections: *Annual Energy Outlook*, Reference Case Projections, Various Editions.

Historical Data: U.S. Energy Information Administration, September 2014 Monthly Energy Review, DOE/EIA-0035(2013/08) (Washington, DC, September 25, 2014), Table 7.1.

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