COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

APPLICATION OF

PATH ALLEGHENY VIRGINIA TRANSMISSION CORPORATION

CASE NO. PUE-2009-00043

For certificates of public convenience
and necessity to construct facilities:
765 kV Transmission Line through
Loudoun, Frederick, and Clarke Counties

DIRECT TESTIMONY

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On Behalf of the Sierra Club

October 23, 2009

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I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Robert M. Fagan. I am a Senior Associate at Synapse Energy Economics, Inc., 22 Pearl Street, Cambridge, Massachusetts, 02139.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I am an energy economics analyst and mechanical engineer with over 20 years of experience in the energy industry. My work has focused on myriad electric power industry issues, including economic and technical analysis of competitive electricity markets development, electric power transmission pricing structures, examination of utility-scale wind power potential and integration, and assessment and implementation of demand-side resource alternatives. I hold an M.A. from Boston University in Energy and Environmental Studies (1992) and a B.S. from Clarkson University in Mechanical Engineering (1981). Details of my experience are provided in my resume as Exhibit RMF-1.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Sierra Club.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to examine and evaluate aspects of the applicants' (Allegheny Power, AEP, and PJM) i) overall analytical approach and ii) transmission system modeling details, in their assertion of a reliability need for the proposed Potomac Appalachian Transmission Highline ("PATH"). In doing so, I analyze in particular fundamental technical considerations and the manner in which they are treated in the proponents' application for approval of the proposed PATH facilities:

- The reasonableness of key input assumptions used in PJM's transmission reliability modeling, particularly the magnitude of energy efficiency ("EE") and demand response ("DR") resources (in aggregate, "demand side" resources);
- The reasonableness of PJM's use of a January 2009 vintage peak load forecast (based on 4th quarter 2008 data) in support of its assertion for PATH need;
- The temporal duration of actual peak loads in PJM, and how such duration invites assessment of generation and demand-side "peaking" resource alternatives to the proposed PATH resource, which PJM did not do; and
- The level of generation resources in PJM's generation interconnection queue, and a comparison to the level of new generation resources used in their transmission reliability modeling.

I also document the lack of any economic cost/benefit analysis by the applicants of the proposed $1.85 billion PATH line, and the lack of such analysis for any of the alternatives to PATH for resolving alleged reliability concerns. Those alternatives include the use of demand-side and generation resources, and possibly lower-voltage reinforcement options.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. It is clear that the alleged need for the PATH line is significantly dependent on peak load growth, in particular in the Mid-Atlantic region of PJM.[1] All of PJM's modeled

1 Exhibit PFM-2 contains a list of the alleged thermal reliability violations, which are dominated, especially in the earlier years of purported need, by "Mid-Atlantic Load Deliverability" test violations. The response to Sierra VA Sierra VA VI-3, Attachment A illustrates that PJM's analysis for future year grid effects involve an extrapolation of load growth trends.

"violations" in Exhibit PFM-1, PFM-2 and PFM-3 depend heavily on the load forecast and demand-side resource forecast used. The Mid-Atlantic region of PJM (also known as "MAAC"[2]) includes the service territories of the original PJM members, and essentially is comprised of customers located in central and eastern Pennsylvania, New Jersey, Maryland, the District of Columbia, and Delaware. However, in analyzing load growth and resource availability in the region, PJM

i. Fully excludes 2,908 MW of PJM-approved demand-side resources in the Mid-Atlantic region (more than 5% of the 2009 Mid-Atlantic peak load[3]), and 371 MW in the Dominion (Virginia) zone, available beginning in 2012 and already secured as a resource by PJM through its May 2009 capacity procurement process known as "RPM" (reliability pricing model)[4]. Demand-side resources are a FERC and PJM-approved capacity resource, yet due to the timing of PJM's most recent capacity procurement (May, 2009), the largest increase of such resource availability in PJM's history has not been considered in the PATH technical analyses (the latest of which were undertaken in March and April of 2009, just before the capacity procurement results were known);

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2 "MAAC" is an acronym for "Mid-Atlantic Area Council", which was the North American Electric Reliability Council ("NERC") sub-region defined by the original PJM utilities. PJM still uses this designation to describe this sub-region of PJM, which includes the electric utility service territories of PECO (formerly, Philadelphia Electric Company), PPL (formerly, Pennsylvania Power and Light), PenElec, MetEd, Public Service Electric and Gas (PSEG), Jersey Central Light and Power (JCPL), Atlantic Electric (AEC), RECO (Rockland Electric Co.), BGE (Baltimore Gas and Electric), PEPCO (Potomac Electric Power Company), and the Delmarva Peninsula (DPL). The NERC sub-region boundaries and names have undergone considerable change in recent years; the original PJM utility service territory areas are now part of the NERC sub-region known as "ReliabilityFirst Corporation" (http://www.rfirst.org/), one of eight NERC sub-regions.

3 PJM, "Summer 2009 Weather Normalized Coincident Peaks (MW)", October 16, 2009. The PJM RTO total weather normalized coincident peak load in 2009 was 133,780 MW. A summation of the Mid-Atlantic load zone values from that publication results in a MAAC normalized summer 2009 coincident peak of 57,590 MW. Available at http://www.pjm.com/planning/resource-adequacy-planning/~/media/planning/res-adeq/load-forcast/summer-2009-pjm-scps-and-w-n-zonal-peaks.ashx and attached as Exhibit RMF-5 of this testimony.

4 Exhibit RMF-2 to this testimony contains PJM's report on the May 2009 RPM auction.

ii. Does not consider more than 2,000 MW (by 2015) of peak-load-reducing energy efficiency and demand response resources under development through electric utility programmatic efforts and other vehicles (pursuant to state law or policy) in all the PJM Mid-Atlantic states, the District of Columbia and Virginia. These resources are in addition to the 2,908 MW of excluded Mid-Atlantic demand-side resources noted above; and

iii. Uses an outdated peak load forecast released in January 2009 that uses fourth quarter 2008 data, during a time of one of the largest economic downturns in US history. The economic downturn has led to dramatically reduced electricity use in the region, and by PJM's own reckoning the 2009 summer coincident peak load in the Mid-Atlantic region of PJM was 3.4% lower than PJM's forecast peak for the Mid-Atlantic region from the January 2009 PJM Load Report.[5]

Thus, PJM has used wholly unreasonable demand-side modeling assumptions in support of its assertion of PATH need.

Futhermore, PJM fails to explore any alternative solutions to the alleged reliability concerns that consider the use of either demand-side resources or generation supply located in the Mid-Atlantic region. PJM does no modeling of the effect on PATH purported need of reducing the "net peak load" (i.e., the forecast peak load net of demand-side resources) seen on the grid. Instead, PJM proposes PATH as a solution to a peaking problem. The actual duration of the highest peak loads seen in summer in the Mid-Atlantic region is limited to relatively brief periods of time.

5 Exhibits RMF-3 and RMF-4 to this testimony contain PJM's January 2008 and January 2009 Load Forecast Reports, respectively.

PJM undertakes neither a direct nor a comparative economic analysis of the PATH line or feasible alternatives. PJM did not quantify the DR and EE resources that would defer or eliminate the need for PATH. PJM limits its inclusion of future Mid-Atlantic area generation resources to approximately one-tenth the level of generation that has indicated interest in connecting to the grid in the Mid-Atlantic region. PJM does not conduct sensitivity analyses of the how the grid might be effected if such generation were to come online in future years (2014 and beyond).

My testimony here will first provide summary background information on facets of the PJM electric market structure that is relative to the issues I address. I then proceed to demonstrate the following:

1. **Using current data on DR and EE resource availability, the "net peak load" PJM projects in its PATH analysis for 2014 for the Mid-Atlantic region will not be seen until 2018.** PJM uses outdated data on demand response and energy efficiency resource availability such that their modeling fails to properly reflect the net peak load that the transmission system would see in 2014, which is PJM's purported "year of need" for the PATH line. Properly incorporating PJM's May 2009 RPM results on demand response and energy efficiency resource availability leads to an outward shift of four years in the net peak load that would be seen by PJM's Mid-Atlantic region. This four year shift results from correcting just the first of the three major load-side input assumptions I identify above (namely DR/EE from the 2012/13 RPM auction that has yet to be modeled by PJM, additional DR/EE from state level initiatives in the Mid-Atlantic region, and an updated load forecast). I next describe the impact on the net peak load when the remaining two assumptions are corrected.

2. **Using current data on DR and EE resource availability <u>and</u> incorporating the additional effect of state-level DR and EE initiatives, the "net peak load" PJM projects in its PATH analysis for 2014 for the Mid-Atlantic region will not be seen until 2021.** Including projections of additional energy efficiency and demand response resources (beyond those available as a result of the May 2009 PJM RPM) estimated to be available in 2014 and later years in PA, NJ, MD, DE, DC, and Virginia further shifts outward the net peak load level that will be seen on the transmission system. PJM currently assumes that none of these additional resources will be available, even though state laws in PA, MD, and DE mandate such resources, and state policies and electric utility actions in NJ, VA and DC target significant peak load reduction. The information available from those jurisdictions illustrates how much EE and DR additional to that already reflected in the most recent RPM results will be available – over 2,000 MW of peak load reduction in the Mid-Atlantic region by 2015. Based on this estimate, along with the DR and EE resources from the 2012/13 RPM auction, the net peak load in the Mid-Atlantic region that PJM forecasts for 2014 – the year PJM says PATH is needed - will not be seen until 2021.

3. **Including an adjusted load forecast in addition to the DR and EE resource additions noted above shifts PJM's net peak load from 2014 to at least 2022.** PJM bases its current assessment on a load forecast prepared in December 2008 based on data available in the last quarter of 2008. By PJM's own reckoning, these data are outdated and contain too high an estimate of peak load growth. This past summer's coincident peak load in all of PJM was approximately 0.48% lower than PJM's January 2009 forecast load for the summer of 2009 for all of PJM, and the Mid-

Atlantic region load was 3.4% lower than forecast in January 2009. Using this information and adjusting PJM's forecast, the net peak load seen by the Mid-Atlantic region shifts out another year, to 2022, relative to the net peak load estimate that incorporates updated DR and EE resources.

4. **Peak load duration and reliability alternatives to PATH**. The PATH purported need is driven by extreme peak load levels that, if they do occur, occur for only a very small fraction of summer periods. For example, the PJM Mid-Atlantic region summer 2008 peak load of 59,653 MW occurred for just one hour; and the "top 50" hours of peak loading (over the course of 10 different days in the summer of 2008) make up the last increment of 7,540 MW of peak load. Thus, the last 13% of the peak load level was seen for less than 1% of the time in 2008. This pattern holds for all recent years (2006 through 2008), and represents the nature of a summer peaking system. PATH is a $1.85 billion interregional transmission project being proposed as a solution to a subregional "peaking" problem. The peaking need requirement could met with less expensive eastern MAAC/southwestern MAAC demand-side resources or generation, but an examination is required to determine this – and PJM has not analyzed this possibility. That PJM states its hands are tied with respect to demand-side and generation "market" solutions[6] does not validate their assertion of need for transmission, it just illustrates the lack of analysis of alternative solutions.

5. **No Economic Analysis Provided for a $1.85 Billion Proposed Facility**. PJM has not conducted any comprehensive economic analysis of the proposed PATH line. PJM provides no current estimate of the annual congestion or line loss savings

[6] Direct Testimony of Steven Herling, pages 51-52.

associated with the project. PJM does not prepare any benefit/cost assessment, or attempt to illustrate savings that may contribute towards offsetting the annual revenue requirement of $365 million that will be imposed on PJM consumers if the line is built. PJM has not prepared any assessment of comparable net costs of solutions such as peaking generation or additional demand response or energy efficiency. Earlier "market efficiency" analyses conducted by PJM show savings to load of only $47 million per year, thus the only information available on the potential economic benefits illustrates order-of-magnitude higher costs than benefits.

6. **Conclusions**. Based on my examination of PJM modeling assumptions for demand response resources, energy efficiency resources, and peak load forecast I conclude that the exclusion of considerable DR and EE resources made available through the 2012/13 RPM auction; the lack of consideration of additional legislated or policy-initiated state utility demand side initiatives in VA, MD, DC, DE, PA and NJ; and the use of an outdated load forecast all results in a flawed transmission need modeling result: simply put, net peak load in the Mid-Atlantic region is not what is forecast in the modeling for the PATH line, as the modeling estimate is not going to be reached until later years well beyond 2014. I also conclude that PJM has failed to sufficiently analyze demand-side and generation alternatives to the reliability concerns they express, especially given the limited duration of the peak load patterns in the Mid-Atlantic region, and given the lack of any comprehensive economic analysis of either the proposed transmission project or other alternatives.

7. **Recommendation.** My primary recommendation is that the Virginia State Corporation Commission deny the application outright due to the unsupported

assertions of need for the proposed PATH line. Alternatively, at a minimum the applicants must re-analyze the alleged need for PATH using current, reasonable input assumptions for demand-side resources and forecast peak load. Such assumptions should clearly include the results of the May 2009 RPM auction and the demand-side resources made available by that auction, and should also recognize the contribution to peak load reduction that will arise from the state-level initiatives identified and described in this testimony. The assumptions should also include a current peak load forecast. As part of any required re-examination of alleged PATH need, the applicants should analyze alternative reliability solutions and should conduct a full economic assessment of the effect on PJM ratepayers of the different alternatives.

II. RELEVANT BACKGROUND ON TRANSMISSION SYSTEM MODELING, ENERGY EFFICIENCY, DEMAND RESPONSE, AND GENERATION RESOURCES AND RPM

Q. WHAT BACKGROUND DO YOU DESCRIBE IN THIS SECTION?

A. I briefly describe relevant aspects of the PJM region and market structure as context for the issues I address in the body of this testimony. These include the following:

1. **Net Peak Load**. For the purposes of this testimony, I use the term “Net Peak Load” to define the peak load seen or modeled on the transmission system net of any demand-side resources – demand response and/or energy efficiency – that are seen or modeled.
2. **PJM RPM Market**. The PJM “Reliability Pricing Model” or RPM market is the capacity market for which existing and new generation and demand-side resources receive revenue streams for providing reliable capacity for the transmission grid. The

payments received for capacity are in addition to revenues received for energy and/or ancillary service provision in PJM. The RPM market is designed to provide pricing incentives for generators to locate in regions that require generation for reliability (thus the name, RPM). As PJM has noted, the RPM helps to ensure that units needed for reliability do not retire, and that new units needed in constrained areas have an incentive to invest and locate in those regions.

3. **Energy Efficiency and Demand Response as Resources**. PJM allows demand response resources to serve as firm, reliable capacity. As of May 2009, PJM also allows energy efficiency resources to serve as firm, reliable capacity. PJM uses the RPM construct to allow such capacity to "compete" with generation in the provision of reliable capacity for the grid.

4. **Energy Efficiency Affect on Peak Load**. In general, the implementation of energy efficiency resources lowers peak load. In addition to reducing consumption of energy (kWh), energy efficiency implementation can also reduce end-user load or demand (kW) during utilities' peak usage period. Utility-sponsored energy efficiency programs usually plan for peak load reducing effects as part of such programs.

5. **PJM Load Forecast Treatment of Energy Efficiency Resources**. PJM's econometric-based load forecast accounts for historical trends in energy efficiency seen in the individual utility service territories, but does not subtract planned energy efficiency savings, or account for any potential changes to historical trends that might be relevant. That would include, for example, the effect on future load of changes in state policy or state law that require increasing amounts of electric energy efficiency beyond what would occur in the absence of such directives.

6. **PJM Treatment of Energy Efficiency and Demand Response for Transmission Planning**. PJM limits the ability of demand response and energy efficiency resources to provide firm capacity to resources that have cleared in the RPM auctions, even though the RPM auctions are only for a single year's worth of capacity. PJM does not consider additional energy efficiency or demand response resources beyond those that have cleared in the most recent RPM auction as resources potentially able to resolve future reliability concerns.

7. **PJM Does Not Conduct Sensitivity Analysis**. PJM does not conduct any sensitivity analyses that evaluate the extent to which purported need for PATH might be eliminated or deferred by alternative projections of demand-side (i.e., demand response and/or energy efficiency) or supply side (i.e., generation) resource availability in future years.

8. **PJM Incorporates "Approved" Transmission Into the Modeling for RPM**. Once a transmission facility has been approved by PJM, it incorporates that facility into the modeling for RPM capacity. Such inclusion bias' the RPM auction outcome against generation and demand side resources that might otherwise have cleared such an auction absent the presence of the line in the auction model, and could otherwise provide reliability support to the grid.

III. THREE CRITICAL FACTORS SHIFT PJM'S CURRENT "NET PEAK LOAD" MID-ATLANTIC 2014 FORECAST BY EIGHT YEARS, TO 2022

Q. WHAT DO YOU EXAMINE IN THIS SECTION?

A. I examine three critical factors that have a dramatic material effect on PJM's assertion that PATH is needed in 2014 for reliability reasons. First, I address PJM's exclusion from their April 2009 retool analysis (which uses data from the January 2009 Load Forecast Report) of key demand response and energy efficiency resources available in the Mid-Atlantic region of PJM. Inclusion of those resources leads to a reduction in "net peak load" such that PJM's forecast value for the Mid-Atlantic region net peak load for 2014 is not reached until 2018. Next, I present data from state initiatives for energy efficiency and demand response in Maryland, Delaware, New Jersey, the District of Columbia, and Pennsylvania and show how use of that data to estimate a further reduction in net peak load leads to a further shift in the Mid-Atlantic region net peak load such that PJM's forecast value for 2014 is not reached until 2021. Last, I update PJM's outdated load forecast, and I estimate that such an updated load forecast would further push out PJM's current estimate of Mid-Atlantic region net peak load for 2014, to at least 2022. Thus, when all three demand-side elements that PJM did not consider are incorporated into a revised estimate for net peak load for the Mid-Atlantic region of PJM, the net peak load forecasted by PJM for 2014 for use in the transmission planning model would not be reached until at least 2022.

PJM May 2009 RPM Demand Response and Energy Efficiency Resources

Q. DOES THE PRESENCE OF DEMAND RESPONSE AND ENERGY EFFICIENCY RESOURCES AFFECT TRANSMISSION NEED?

A. Yes. Demand response and energy efficiency, properly located, directly reduce the peak load seen on the transmission system and thus reduce the need for reinforcement of the grid. Demand response and energy efficiency resources are netted against peak load forecasts in PJM's process of analyzing the extent of projected "load deliverability" reliability concerns.

Q. DID PJM INCLUDE THE EFFECT OF THEIR MOST RECENTLY APPROVED DEMAND RESPONSE AND ENERGY EFFICIENCY RESOURCES IN THEIR ASSESSMENT OF NEED FOR PATH?

A. No. The data used to represent demand response and energy efficiency resources in the modeling used to assert PATH need are of 2008 vintage, even though more recent data is available from May of 2009. In particular, PJM's May 2009 procurement of demand-side capacity resources, through the RPM capacity market, was the largest procurement of demand-side resources in its history. The results presented by PJM in Exhibit PFM-2 for its analysis of load deliverability are thus based on outdated data. Using the most recent data, an increase in demand response and energy efficiency resource availability is seen.

Q. WHAT IS THE INCREASE IN DEMAND RESPONSE AND ENERGY EFFICIENCY RESOURCE AVAILABILITY ARISING FROM THE RECENTLY COMPLETED RPM AUCTION, RELATIVE TO PJM'S MODELING OF THOSE RESOURCES?

A. Table 1 below shows the increase. In 2012, there is an increase of 2,908 MW of demand side resources in the Mid-Atlantic region compared to the level PJM has included in its April 2009 retool modeling of transmission line need. This increase is comprised in part by an increase of over 1,000 MW available in the eastern Mid-Atlantic region (a subset of the Mid-Atlantic region, known as EMAAC). EMAAC is the region encompassing New Jersey, the Delmarva Peninsula and the PECO service territory. There is also 972 MW of additional demand side resource in the Southwest Mid-Atlantic region ("SWMAAC", another subset of the Mid-Atlantic region, consisting of the PEPCO and BGE territories) just east and southeast of the proposed eastern terminus of the PATH line at Kemptown. And there is 371 MW of additional resources for the Dominion region (outside of the Mid-Atlantic area, but electrically close to the Kemptown terminus).

Table 1. Increase in Available DR and EE for 2012 Compared to PJM Modeled Levels

Delta (DR + EE), MW	2009	2010	2011	2012	2013	2014	2015
MAAC	0	0	0	2,908	2,908	2,908	2,908
EMAAC	0	0	0	1,046	1,046	1,046	1,046
SWMAAC	0	0	0	972	972	972	972
DOM	0	0	0	371	371	371	371

Note: There is no change to available DR and EE in 2009 through 2011 because the RPM results are for three years ahead; that is, I do not assume any increases in DR and EE relative to PJM's modeling for the years 2009 through 2011. Source: Computed from the difference between the values in Tables 2 and 4 below.

Q. WHAT LEVEL OF DEMAND RESPONSE AND ENERGY EFFICIENCY WAS USED BY PJM IN THE MODELING FOR THE PROPOSED LINE?

A. In their most recent analysis, PJM uses demand response and energy efficiency resources based on the information in the PJM 2009 Load Forecast Report (January, 2009). These resources include a combination of DR cleared in the 2011/12 RPM auction (held in May, 2008) and interruptible load resources (ILR); energy efficiency resources are listed as zero in the report for all PJM regions (Table B-8 of the report), since the incorporation of these resources into PJM's planning framework only commenced with the May 2009 RPM auctions. PJM's modeling does not include the additional 2,908 MW of DR and EE shown in Table 1 for the Mid-Atlantic region. Table 2 below shows PJM's levels of demand response values for the MAAC, EMAAC, and SWMAAC regions, and for the Dominion (Virginia Power) territory ("DOM").

Table 2. Demand Response and Energy Efficiency Used by PJM Modeling for Proposed PATH Line

DR + EE, MW	2009	2010	2011	2012	2013	2014	2015
MAAC	2,311	1,863	1,996	1,996	1,996	1,996	1,996
EMAAC	1,033	684	613	613	613	613	613
SWMAAC	904	747	961	961	961	961	961
DOM	28	23	126	126	126	126	126

Source: PJM, Table B-7, January 2009 Load Forecast Report. MAAC values taken directly. EMAAC values based on sum of values for NJ, DPL, and PECO territories. SWMAAC values are the sum of BGE and PEPCO values. Table B-8 of same report indicates that EE values for all regions are zero.

Q. DO TABLE 2 VALUES REPRESENT THE MOST RECENT INFORMATION AVAILABLE FOR DR AND EE THAT WILL BE A RESOURCE TO PJM?

A. No. In May of 2009 (subsequent to the re-tool conducted by PJM in April of 2009) the most recent RPM auction cleared an unprecedented increase in the amount of demand response – and for the first time in an RPM auction, energy efficiency – available for use as a capacity resource throughout PJM. This includes substantial increases over the values in Table 2 above for the MAAC, EMAAC, SWMAAC and Dominion (DOM) areas. Table 3A below reproduces a table from the PJM RPM auction report in May 2009 that shows the level of offered and cleared demand response and energy efficiency resources by utility service territory. Table 3B illustrates the increase in cleared demand-side resources between the May, 2008 2011/12 RPM auction (used by PJM in their PATH modeling) and the May 2009 2012/13 RPM auction, also by utility service territory.

Table 3A. DR and EE Offered and Cleared in the 2012/13 RPM Auction (May, 2009)

	Offered MW*			Cleared MW*		
Zone	Demand	EE	Total	Demand	EE	Total
AECO	78.9	1.9	80.8	75.1	1.2	76.3
AEP	1352.7	2.6	1355.3	710.8	0	710.8
APS	582.4	0	582.4	272.9	0	272.9
BGE	1370.6	105.8	1476.4	1312.9	103.2	1416.1
COMED	1049	386.4	1435.4	658	386.4	1044.4
DAY	405.6	0	405.6	112.3	0	112.3
DOM	1237.9	76.6	1314.5	494.7	2.4	497.1
DPL	289.6	12.7	302.3	283	12.2	295.2
DUQ	190.8	0.2	191	74.8	0.2	75
JCPL	362.7	2.8	365.5	321.9	1.8	323.7
METED	267.2	0	267.2	252	0	252
PECO	581.2	2.9	584.1	496.4	1.9	498.3
PENELEC	286.1	0.2	286.3	276.3	0.2	276.5
PEPCO	485.1	56.5	541.6	460.8	56.5	517.3
PPL	832.9	0	832.9	783.3	0	783.3
PSEG	472.9	4.1	477	460.1	2.9	463
RECO	2	0	2	2	0	2
Total	9847.6	652.7	10500.3	7047.3	568.9	7616.2

*All MW Values are in UCAP Terms

Table Source: PJM, 2012/2013 RPM Base Residual Auction Results, Table 3A, "Comparison of Demand Resources and Energy Efficiency Resources Offered versus Cleared in the 2012/13 BRA represented in UCAP". May 2009.

Table 3B. Comparison of DR and EE Offered and Cleared in the 2011/12 RPM Auction vs. DR and EE Offered and Cleared in the 2012/13 RPM Auction (May, 2009)

	Offered MW*			Cleared MW*		
Zone	2011/2012	2012/2013	Increase in Offered MW	2011/2012	2012/2013	Increase in Cleared MW
AECO	11.7	78.9	67.2	7	75.1	68.1
AEP	24.2	1352.7	1328.5	14.6	710.8	696.2
APS	88.6	582.4	493.8	57.3	272.9	215.6
BGE	628.3	1370.6	742.3	595.8	1312.9	717.1
COMED	158	1049	891	127.3	658	530.7
DAY	25.4	405.6	380.2	15.3	112.3	97
DOM	155.8	1237.9	1082.1	105.9	494.7	388.8
DPL	58.9	289.6	230.7	43.8	283	239.2
DUQ	0	190.8	190.8	0	74.8	74.8
JCPL	55.4	362.7	307.3	46.4	321.9	275.5
METED	23.8	267.2	243.4	14.3	252	237.7
PECO	131.3	581.2	449.9	103.2	496.4	393.2
PENELEC	27.1	286.1	259	16.2	276.3	260.1
PEPCO	150.9	485.1	334.2	144.8	460.8	316
PPL	63.4	832.9	769.5	42.2	783.3	741.1
PSEG	49.6	472.9	423.3	30.8	460.1	429.3
RECO	0	2	2	0	2	2
Total	1652.4	9847.6	8195.2	1364.9	7047.3	5682.4

*All MW Values are in UCAP Terms

Table Source: PJM, 2012/2013 RPM Base Residual Auction Results, Table 3B, "Comparison of Demand Resources Offered and Cleared in 2011/12 BRA & 2012/13 BRA represented in UCAP. May 2009.

Table 4 below aggregates the cleared 2012/13 values in the table above to produce the levels for MAAC, EMAAC, SWMAAC, and includes the Dominion region also.

Table 4. Updated Levels of DR and EE Based on Results of 2012/13 RPM Auction

DR + EE, MW	2009	2010	2011	2012	2013	2014	2015
MAAC	2,311	1,863	1,996	4,904	4,904	4,904	4,904
EMAAC	1,033	684	613	1,659	1,659	1,659	1,659
SWMAAC	904	747	961	1933.4	1933.4	1933.4	1933.4
DOM	28	23	126	497.1	497.1	497.1	497.1

Q. HAS PJM UPDATED THEIR PATH ANALYSIS TO TAKE THIS INCREASED DEMAND SIDE RESOURCE AVAILABILITY INTO ACCOUNT?

A. No. PJM has not updated their analyses to take the increased levels into account. The April 2009 retool used the levels of demand response from Table 2 above, and did not use the more recent data shown in Table 3A and summarized for PJM subregions in Table 4.

Thus, PJM has not included the most recent information on demand-side resources that are now available for use in reducing net peak load modeled in their transmission analyses. If they were to include it, it would shift the net peak load for the Mid-Atlantic region out four years – in other words, the levels projected by PJM to occur in 2014 would not occur until 2018. This is seen in Table 5 below.

Table 5. Four Year Outward Shift in Mid-Atlantic Net Peak Load When Using May 2009 RPM Results for Demand Side Resources

	2013	2014	2015	2016	2017	2018
MAAC - Based on PJM's April Retool						
MAAC 90/10 CP Load Forecast, Jan 2009 Ld Rpt	67,890	68,940	69,748	70,590	71,449	71,915
MAAC DR and EE Reduction, Total, Jan 2009 Ld Rpt	1,996	1,996	1,996	1,996	1,996	1,996
MAAC 90/10 CP Net Peak Load Forecast w/o 2012/13 RPM DR+EE Resources	65,894	**66,944**	67,752	68,594	69,453	69,919
MAAC - Including the Effect of the DR/EE Available from the May 2009 RPM Auction						
MAAC 90/10 CP Load Forecast, Jan 2009 Ld Rpt	67,890	68,940	69,748	70,590	71,449	71,915
MAAC DR and EE Reduction, Total, 2012/13 RPM	4,903.70	4,903.70	4,903.70	4,903.70	4,903.70	4,903.70
MAAC 90/10 CP Net Peak Load Forecast with 2012/13 RPM DR+EE Resources	62,986	64,036	64,844	65,686	66,545	**67,011**

Q. PLEASE EXPLAIN HOW PJM MODELS DEMAND SIDE RESOURCES FOR FUTURE YEARS.

A. For transmission modeling purposes, PJM holds constant the level of demand-side resources in future years, equal to the value for the most recently completed capacity procurement for that year and all forward years. In their modeling for the proposed PATH line, PJM held the values constant for 2011 forward based on the information in the January 2009 load forecast report. This is seen in Table 2 above. For example, PJM's value for demand-side resources for the Mid-Atlantic area is held at 1,996 MW for the years 2011 and beyond. For the purpose of showing how demand-side resources would change under PJM's protocols if PJM incorporated the results of the May 2009 RPM auction into their modeling, I too held constant the level of demand-side resources from 2012 forward, as seen in Table 4.

Q. DO YOU THINK DEMAND SIDE RESOURCES WILL BE THE SAME IN FUTURE YEARS AS THEY ARE IN THE MOST RECENT YEAR FOR WHICH RPM RESULTS EXIST?

A. No. Current trends are for increasing levels of demand-side resource availability. For example, existing and developing energy efficiency and peak demand reduction programs in Virginia, New Jersey, Delaware, Maryland, DC, and Pennsylvania all will be a resource source for the PJM RPM market. PJM recognizes that the existence of the RPM market will help support state energy efficiency and demand response efforts, as seen in a PJM document on RPM and demand response and energy efficiency:

> "How does the capacity market fit into a state's master plan for energy?
>
> Participation in the PJM capacity market allows a consumer to monetize their ability to reduce demand for electricity and to monetize energy efficiency measures they have implemented. The consumer will not only experience savings from an altered energy

> consumption pattern but can also receive a revenue stream for helping to increase the reliability of the electric system that serves them. RPM provides a revenue stream to make demand response and energy efficiency viable alternatives in support of state energy master plans."
>
> Source: PJM, "Reliability Pricing Model, Demand Response and Energy Efficiency", April 6, 2009, available at http://www.pjm.com/markets-and-operations/demand-response/~/media/markets-ops/rpm/20090406-dr-ee-in-rpm-collateral.ashx

Q. WHAT IS THE EXPERIENCE OF OTHER REGIONS WITH DEMAND RESPONSE AS A CAPACITY RESOURCE?

A. Other regions have seen increases in the availability of demand response resources. For example, ISO-NE (the Independent System Operator for New England, analogous to PJM) has shown increased levels of DR and EE in each of its subsequent capacity market auctions, which use a similar construct as PJM.

Q. IS THERE SIGNIFICANT POTENTIAL FOR ADDITIONAL DEMAND RESPONSE AND ENERGY EFFICIENCY IN THE PJM REGION?

A. Yes. Both demand response and energy efficiency potential is considerable. Figure 1 below illustrates demand response potential by census region based on a June 2009 FERC Staff Report, "A National Assessment of Demand Response Potential".[7] As indicated, as a percentage of peak load demand response potential in the Mid-Atlantic region could reach as high as 17% of peak load. Based on the May 2009 PJM RPM results shown in Table 3A, and summarized in Table 4, current Mid-Atlantic region demand response of 4,724 MW represents 7.4% of PJM's 50/50 2012 Mid-Atlantic peak demand of 63,556 MW (based on the January 2009 load forecast), thus confirming the presence of significant additional demand response. Various recent reports on energy

7 Available at http://www.ferc.gov/legal/staff-reports/06-09-demand-response.pdf.

efficiency potential in the region confirm the potential for savings illustrated in the next section of this testimony on state-level energy efficiency initiatives.

Figure 1. Table ES-3 from the National Assesssment of Demand Response Potential

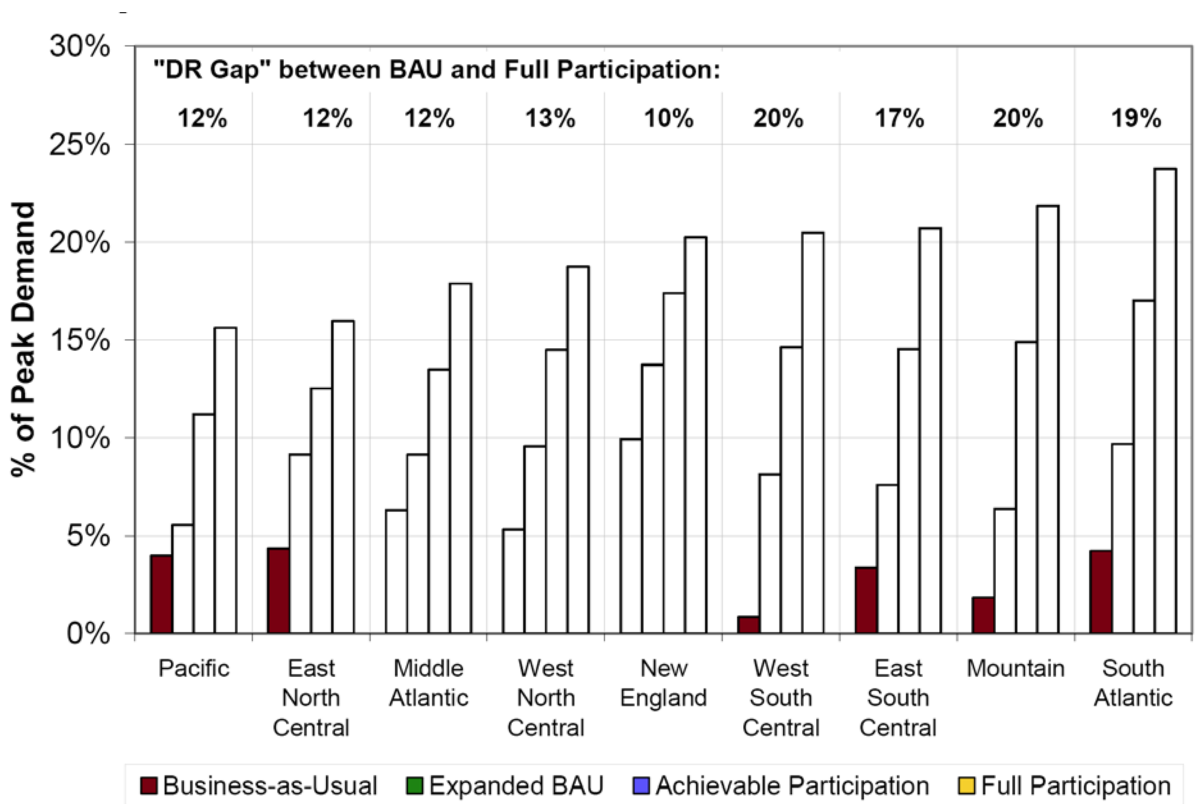

Figure ES-3: Demand Response Potential by Census Division (2019)

<u>State Initiatives for Energy Efficiency and Demand Response</u>

Q. WHAT DO YOU PRESENT IN THIS SECTION?

A. I identify, describe, and to the extent possible quantify[8] the energy efficiency and demand response resources that will be available pursuant to state level initiatives in the PJM Mid-Atlantic and Dominion (Virginia) region. These resources will help to reduce the

8 As will be noted in this section, I subtract out all 2012/13 RPM cleared DR and EE resources from the gross totals of peak load reduction reported for DR and EE resources pursuant to the state initiatives for BGE, PEPCO, and DPL. This is a conservative approach, in that at least some of the 2012/13 cleared RPM quantities in these states are likely sourced from DR providers other than the utility companies that are developing and implementing the state initiatives.

reliability concerns expressed by PJM because their effect is to reduce the net peak load in their respective regions.

Q. DOES PJM INCLUDE, IN ITS MODELING OF PATH ALLEGED NEED, THE PEAK-LOAD REDUCING EFFECT OF PLANNED ENERGY EFFICIENCY AND DEMAND RESPONSE PROGRAMS FROM THE STATES OF NJ, PA, MD, DE, VA AND THE DISTRICT OF COLUMBIA?

A. Generally, no. The possible[9] exceptions to this are program resources, primarily demand response resources in the SWMAAC region and the DPL service territory, that have already cleared PJM's RPM auction for capacity resources; although as noted in the above section, even these resources cleared in the 2012/13 RPM auction are not included in PJM's April 2009 retool modeling.

Q. WHAT STATE ENERGY EFFICIENCY AND DEMAND RESPONSE EFFORTS ARE NOT INCLUDED IN PJM'S ANALYSIS?

A. Energy efficiency and demand response initiatives in Virginia, Maryland, the District of Columbia, Delaware, Pennsylvania, and New Jersey are generally excluded from consideration as potential peak load reducing resources in these states. These initiatives primarily take the form of utility-sponsored "demand side management" programs targeted to reduce peak load through demand response and energy efficiency implementation pursuant to state law, state policy, and/or utility commission directives.

Q. DO THESE STATE-INITIATED EFFORTS HELP REDUCE NET PEAK LOAD?

9 For the purposes of this testimony, I have presumed that EE and DR resources cleared in the SWMAAC and DPL regions of PJM in the 2012/13 auction are part of the state utility initiative savings seen in Maryland and the District of Columbia and Delaware, since PJM RPM auction results do not publicly indicate the source of EE and DR savings in any given region. This is a conservatism, as to the extent that these cleared resources are sourced outside of the state initiated utility programs, they represent savings incremental to utility efforts.

A. Yes, absolutely. Peak load reduction in these areas, through EE or DR, is electrically important from the perspective of mitigating alleged need for additional generation or transmission such as the proposed PATH line. The BGE and PEPCO service territories in Maryland (together, the Southwest Mid-Atlantic region, or SWMAAC), for example, are electrically "downstream" from the planned terminus of the PATH line at Kemptown. In addition, New Jersey and Pennsylvania and Delaware demand-side resources all contribute towards reduced Eastern Mid-Atlantic, and Mid-Atlantic, peak loads. And much of the Dominion Power service territory in Virginia is located in the northern and eastern regions of the state, and thus is also electrically downstream of the main 500 kV facilities that make up the asserted reliability concerns shown in Exhibit PFM-2.[10]

Q. PLEASE SUMMARIZE THE EFFECT THAT THESE RESOURCES HAVE ON THE "NET PEAK LOAD" THAT UNDERLIES THE NEED FOR PATH.

A. The following Table 6 contains an estimate out to 2019[11] of the <u>additional</u> peak-load-reducing effect of these planned resources that are not currently considered by PJM in their analysis of need. These reductions are in addition to both the EE and DR resources that have already cleared in the 2012/13 RPM auction, though I emphasize again that those 2012/13 RPM cleared resources have not yet been included in PJM's analysis as resources that can help mitigate purported PATH need, and are also additional to any peak load reduction that would result from use of a more current peak load forecast.

10 See response to Sierra VA VI-3, Attachment A, Table 4, which contains the distribution factors for the PJM load zones with respect to the Mt. Storms-Doubs constraint. All of the cited service territories above, with the exception of Penelec, exhibit positive distribution factors, which illustrates that peak load reduction in these areas contributes towards mitigating the impact on a key facility for which PATH is proposed as a reliability solution.

11 The savings continue beyond 2019.

Table 6. Additional Peak Load Savings Available from State Level EE and DR Initiatives

	2013	2014	2015	2016	2017	2018	2019
Virginia	270	367	420	469	513	551	580
Maryland/DC (BGE, PEPCO)	212	265	257	257	257	257	257
New Jersey	525	788	1,050	1,313	1,575	1,838	2,100
Delmarva Peninsula	95	165	226	226	226	226	226
Pennsylvania	608	608	608	608	608	608	608
Mid-Atlantic Total	1,440	1,825	2,140	2,403	2,665	2,928	3,190

Note: Not Considered in PJM's PATH Need Modeling and Not Already Accounted for in 2012/13 RPM levels. Sources: EmPower Maryland Filings and MD PSC Orders, DC Commission Filing and Order, NJ Energy Master Plan, PA Act 129, VA SCC Dominion filing. Synapse compilation.

The effect of including the savings in the above table is to push further outward the Mid-Atlantic peak load currently forecast by PJM for 2014. I estimate that including the 2012/13 RPM results pushes outward the forecast load for 2014 to 2018; adding in the resources in the above table pushes out to 2021 the net peak load PJM forecasts for 2014 for the Mid-Atlantic region. The following sections briefly describe the initiatives in each of these regions.

<u>Virginia (Dominion) State Energy Efficiency and Demand Response Initiatives</u>

Q. WHAT IS THE BASIS FOR THE VIRGINIA SAVINGS SHOWN IN TABLE 6?

A. The source of the savings is Schedule 6 of the Direct Testimony of Michael J. Jesensky of Dominion Power in Dominion's DSM Case before this Commission.[12] He includes an estimate of coincident peak savings arising from the 12 EE/DR programs planned by Dominion.

Table 7. Dominion Zone Coincident Peak Savings, MW

	2013	2014	2015	2016	2017	2018	2019
Dominion	270	367	420	469	513	551	580

[12] Available at http://docket.scc.virginia.gov/vaprod/main.asp for Docket PUE-20009-00081.

Southwest MAAC Region State Energy Efficiency and Demand Response Initiatives (Eastern Maryland and District of Columbia)

Q. WHAT IS THE BASIS FOR THE MARYLAND/DC SAVINGS?

A. The source of the savings includes the EmPower Maryland filings and resulting Maryland Public Service Commission Orders for PEPCO/MD and BGE, and the PEPCO/DC filing and DC Commission Orders in that case.[13]

Q. PLEASE SUMMARIZE THOSE FILINGS AND ORDERS AND THEIR BASIS IN STATE LAW OR POLICY.

A. Maryland's "Empower Maryland Energy Efficiency Act of 2008" directed utilities to achieve peak demand savings reductions, and directed the Maryland Commission to oversee and regulate the implementation of the utility EE and DR programs.[14] Table 8 below summarizes the savings values from the Commission orders and filings, and also illustrates how I first subtracted cleared 2012/13 RPM values to obtain the net peak load effect shown in Table 6 above. This step likely underestimates the peak load reduction that will be available from these programs. The first part of the table also includes the gross peak demand reductions from programs that include AMI and smart meter savings estimates; I do not include these peak demand savings in my summary estimate.

[13] Case 9154, November 10, 2008 filing of BGE, revised Table ES-2, peak load reduction. Order 82385 and PEPCO/MD filing in Case 9155, September 1, 2008 filing. District of Columbia Order 15205, March 3, 2009 and PEPCO/DC filing of April 4, 2007.

[14] Md. Public Utility Companies Code Ann. § 7-211 (2009).

Table 8. Southwest MAAC Region Additional Peak Reductions from State Utility Initiatives

SWMAAC Peak Savings MW - Approved Utility Programs
Including All DR From AMI, Smart Meter, Dynamic Pricing

	2010	2011	2012	2013	2014	2015
BGE	928	1,369	1,746	1,805	1,870	1,941
PEPCO MD	263	535	656	716	779	801
PEPCO DC	21	27	51	51	51	51
Total SWMAAC	1,211	1,931	2,452	2,571	2,700	2,792

SWMAAC Peak Savings MW - Approved Utility Programs
Excluding DR From AMI, Smart Meter, Dynamic Pricing

	2010	2011	2012	2013	2014	2015
BGE	928	1,319	1,646	1,630	1,620	1,591
PEPCO MD	166	309	409	468	530	552
PEPCO DC	16	25	48	48	48	48
Total SWMAAC	1,109	1,653	2,103	2,146	2,198	2,191

SWMAAC Total 2012/13 PJM RPM UCAP, MW

	2012	2013	2014	2015
EE	160	160	160	160
DR	1,774	1,774	1,774	1,774
Total EE+DR, SWMAAC	1,933	1,933	1,933	1,933

SWMAAC Incremental Peak Load Reduction Beyond Current 2012/13 RPM Levels
Including Maryland and District of Columbia EE and DR Initiatives

	2012	2013	2014	2015
Total - Approved Utility Programs	2,103	2,146	2,198	2,191
Total - 2012/13 RPM	1,933	1,933	1,933	1,933
Incremental Peak Reduction, MW	169	212	265	257

Delaware and the DPL Zone

Q. WHAT IS THE BASIS FOR THE DPL ZONE SAVINGS?

A. In 2009 Delaware enacted the "Energy Conservation and Efficiency Act of 2009. That act included a requirement to reduce peak demand (MW), and energy consumption (MWh), by 15% by 2015.[15] The estimated savings shown in Table 6 above was computed based on a 15% peak load reduction from Delaware's peak load[16] based on the

[15] Title 26 of the Delaware Code, Chapter 15 – Energy Efficiency Resource Standards, Section 1502 (a)(1), "It is the goal of this chapter that each affected energy provider shall achieve a minimum percentage of energy savings as follows: . . . enery savings that is equivalent to 2% of the provider's 2007 electricity consumption, and coincident peak demand reduction that is equivalent to 2% of the provider's 2007 peak demand by 2011, with both of the foregoing increasing from 2% to 15% by 2015;…"

[16] Delaware peak load is assumed to be just under two-thirds of the DPL zone peak load.

PJM January 2009 Load Forecast Report, and subtracting out the cleared DR and EE savings from the 2012/13 RPM auction. The value also includes an estimate of savings for the non-Delaware remainder of the DPL zone, based on combined Maryland and Virginia DPL zone load achieving a 5% peak demand reduction by 2015.

New Jersey and Pennsylvania State Energy Efficiency Targets

Q. CAN YOU SUMMARIZE THE EASTERN PENNSYLVANIA AND NEW JERSEY PJM REGIONS' ENERGY EFFICIENCY AND DEMAND RESPONSE PLANS?

A. Yes. New Jersey is in the process of implementing energy efficiency programs arising from the state's Energy Master Plan, issued in October 2008, which seeks to dramatically reduce peak load growth by 2020 net of energy efficiency, demand response and some distributed generation.[17] The NJ EMP provision will affect the peak load growth of PSEG, JCPL, AECO and RECO, New Jersey's electric utilities. Pennsylvania utilities must meet the energy efficiency and demand response provisions of Act 129, which requires them to reduce their average peak demand in the top 100 hours of the summer of 2007 to levels 4.5% below that average by the summer of 2012.[18] These provisions affect PA utilities, including MetEd, PPL, and PECO.

Q. PLEASE SUMMARIZE THE PEAK LOAD SAVINGS ANTICIPATED FROM THE NEW JERSEY ENERGY MASTER PLAN ENERGY EFFICIENCY INITIATIVES.

17 "New Jersey Energy Master Plan", October 2008, available at http://nj.gov/emp/docs/pdf/081022_emp.pdf.

18 The provision states that the reduction must be in place by May 31, 2013. 66 Pa. C.S.A. § 2806.1(d).

A. New Jersey plans to reduce peak load by 3,300 MW between its base year of 2004 and 2020, solely from energy efficiency resources.[19] Peak demand for 2020 is projected to be approximately 21,900 MW, exclusive of the effect of intended incremental distributed generation and demand response. PJM currently projects a non-coincident peak of 25,717 MW for the four New Jersey utilities (PJM 2009 Load Forecast Report). Thus there is a difference of roughly 3,800 MW of peak load (in 2020) between what PJM projects for New Jersey, and what New Jersey is aiming for with its Energy Master Plan. New Jersey also plans for additional peak load reduction of 900 MW from demand response resources and 1,500 MW from distributed generation, by 2020.

Depending on the "ramp rate" of such efficiency and demand response gains, New Jersey could see energy efficiency and demand response peak savings in 2014 of anywhere from tens of MW to hundreds of MW, and most these savings are not considered in PJM's modeling of the need for the PATH line since at the time of the May 2009 auction, utility implementation plans had not been finalized.

Q. WHAT IS THE RELEVANT LANGUAGE IN PENNSYLVANIA'S ACT 129 IN REGARDS TO PEAK DEMAND REDUCTION?

A. The relevant language is as follows:

> (1) By May 31, 2013, the weather-normalized demand of the retail customers of each electric distribution company shall be reduced by a minimum of 4.5% of annual system peak demand in the 100 hours of highest demand. The reduction shall be measured against the electric distribution company's peak demand for June 1, 2007, through May 31, 2008.

Source: 66 Pa.C.S. Section 2806.1(d).

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19 The Energy Master Plan also projects demand response savings of 900 MW over this time frame (Plan pp. 60-61), and distributed generation of 1,500 MW. See "Modeling Report for the Energy Master Plan, Appendix A: Business as Usual vs. Alternative Scenarios", October 21, 2008, available at http://www.nj.gov/emp/docs/pdf/10122208ceeepModEMP.pdf (downloaded June 5, 2009).

Q. PLEASE SUMMARIZE THE PERTINENT EFFECT OF PENNSYLVANIA'S ACT 129 ON THE ELECTRIC UTILITIES IN EASTERN PENNSYLVANIA.

A. Table 9 below is reproduced from the Pennsylvania Public Utility Commission's Order from March 26, 2009. It summarizes the level of peak demand reduction that must be attained by May 31, 2013 (the end of the PJM 2012/2013 planning period. The numbers in the statute indicate that the state is aiming to achieve a 1,193 MW peak demand reduction.

Table 9. Reproduction of Peak Demand Savings Table from PA PUC Order Implementing Act 129

Table 2. Average Historical Peak Loads and Act 129 Mandated Peak Demand Reductions as Measured in Megawatts

EDC	Load	4.5% Reduction
Duquesne	2,518	113
Met-Ed	2,644	119
Penelec	2,395	108
Penn Power	980	44
PPL	6,592	297
PECO	7,899	355
West Penn	3,496	157
Total	26,524	1,193

Source: PA PUC Order, Docket No. M-2008-2069887, "Energy Consumption and Peak Demand Reduction Targets", March 26, 2009.

Q. ARE ANY OF THE PEAK LOAD REDUCTIONS PROJECTED HERE INCLUDED IN THE ENERGY EFFICIENCY RESOURCES THAT CLEARED IN THE 2012/13 RPM AUCTION, OR THE PJM JANUARY 2009 LOAD FORECAST?

A. None of these savings are considered in the January 2009 Load Forecast. It is possible that the RPM auction includes amounts that would be obtained through programs or initiatives resulting from the law, but the fraction is so small as to be *de minimus* relative to the required savings. The amount of energy efficiency clearing in the RPM auction from these utilities is very small – a total of 1.9 MW, all from the PECO zone.

Q. IN CONCLUSION, FOR THE PURPOSES OF TRANSMISSION PLANNING, DOES PJM MODEL ANY SIGNIFICANT LEVEL OF THE PROJECTED ENERGY EFFICIENCY OR DEMAND RESPONSE SAVINGS MANDATED BY MARYLAND, PENNSYLVANIA AND DELAWARE LAW, OR BEING IMPLEMENTED AS PART OF NEW JERSEY'S ENERGY MASTER PLAN, AND DOMINION AND THE DISTRICT OF COLUMBIA'S DEMAND-SIDE MANAGEMENT INITIATIVES?

A. With the possible exception of certain demand response resources noted above for BGE, PEPCO and DPL, no.

Q. DOES PJM CONDUCT ANY SENSITIVITY OR SCENARIO ANALYSIS THAT WOULD CONSIDER EVEN A FRACTION OF THE DEMAND RESPONSE OR ENERGY EFFICIENCY RESOURCES FROM ANY OF THESE STATE INITIATIVES?

A. No. PJM does not attempt to assess the sensitivity of their needs analysis to energy efficiency implementation that is not already part of their load forecast or is not cleared in the RPM auction, and essentially treats the reliability value of these extensive initiatives as zero.

Q. EXPLAIN HOW THE INCREMENTAL SAVINGS SHOWN IN TABLE 6 ABOVE FROM ALL OF THESE STATE UTILITY EFFORTS SHOULD BE FACTORED INTO PJM'S PLANNING FOR THE PROPOSED PATH LINE.

A. These savings should be used to further reduce, for planning purposes, the "net peak load" used in the reliability power flow models that underlie PJM's assertion of need for the proposed PATH line. In particular, recognizing that the purported need for the PATH line would not arise until 2018 when considering only those resources that have already cleared the 2012/13 auction, PJM should examine carefully the effects of these initiatives in the years including 2018 and beyond.

<u>Outdated Vintage of PJM Load Forecast</u>

Q. WHAT LOAD FORECASTS ARE USED BY PJM IN ASSESSING ALLEGED NEED FOR THE PATH LINE?

A. In the most recent April 2009 "retool" analysis PJM uses the "PJM Load Forecast Report, January 2009".[20] The claimed reliability violations shown in Exhibit PFM-2 and Exhibit PFM-3 arise from use of the load forecast data in that report. The claimed reliability violations shown in Exhibit PFM-1 arise from use of data from the previous year's report, the "PJM Load Forecast Report, January 2008". The initial PJM Board recommendation for the PATH line, contained in the 2007 RTEP ("Regional Transmission Expansion Plan") report (released in February of 2008) relied on forecast data from the "PJM Load Forecast Report, January 2007".

Q. WHICH LOAD FORECAST DATA FROM THESE REPORTS ARE USED?

20 The 2009 report is available at http://www.pjm.com/documents/~/media/documents/reports/2009-pjm-load-report.ashx. Earlier Load Forecast reports are also available on the PJM website.

A. PJM uses “extreme” summer peak (90/10) load forecasts when assessing purported PATH need.[21] These data are shown on PJM’s Table D-1 in the January 2009 Load Forecast report. An extreme summer peak (90/10) forecast means a forecast that has a probability 00of being exceeded of only 10%, and its use can be thought of as testing the system for reliability on an unusually hot and humid, non-holiday summer weekday.[22]

Q. WHAT OTHER DATA FROM THESE LOAD FORECAST REPORTS ARE USED?

A. The demand response data from the 2009 Load Forecast report is also used. The data is found in Table B-7 of the report.

Q. HOW DOES THE 90/10 EXTREME PEAK LOAD FORECAST CHANGE BETWEEN THE 2008 AND THE 2009 LOAD FORECAST REPORTS?

A. The January 2009 load forecast report reflects significantly lower PJM zonal peak demands than the January 2008 load forecast report. For example, the January 2009 PJM Mid-Atlantic Area coincident peak[23] extreme forecast for summer 2009 (62,452 MW) is 3.5% lower than the previous year’s extreme forecast for summer 2009 (64,724 MW). The peak load in the Mid-Atlantic region is a key driver of the claimed need for the proposed PATH line.

Q. HOW DOES THE JANUARY 2009 FORECAST LOAD COMPARE TO THE ACTUAL LOAD SEEN IN PJM IN THE SUMMER OF 2009?

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21 “Load Deliverability” is tested by PJM using 90/10 forecast loads.

22 PJM’s 2009 Load Forecast report 90/10 forecast load for the Mid-Atlantic region is 4.75% higher than the “normal” or “50/50” forecast load. This is a measure of the extent of “extremeness” used in the transmission planning model.

23 Coincident peak refers to the actual peak load seen across several or many regions or zones, and it accounts for the fact that not all zones will experience their own peak demand at the same time as other zones. Coincident peak load across a series of zones is usually lower than the sum of the non-coincident peak loads for those same zones.

A. Actual summer 2009 peak load in the Mid-Atlantic region was 3.4% lower than PJM's January 2009 forecast of peak load for that region, the same load forecast report used by PJM in its April 2009 "retool" of alleged PATH need. On October 6, 2009, PJM released the "Summer 2009 Weather Normalized Coincident Peaks (MW)"[24] data. This contained the data for each of the PJM zones. Summing the data for the Mid-Atlantic region, the weather-normalized peak load was 57,690 MW. The 50/50 forecast peak load for 2009 from the January 2009 Load Forecast Report for the Mid-Atlantic region was 59,621 MW, or 2,031 MW higher than the actual (weather-normalized) peak load seen in the summer of 2009.

Q. WHAT DOES THIS MEAN?

A. This means that PJM's January 2009 Load Forecast Report overestimated the level of summer 2009 peak load in the Mid-Atlantic region by 3.4%. Since the data released was corrected for weather effects, and the 50/50 peak load forecast From the January 2009 Load Forecast Report also represents a "weather normalized" forecast, the two values are directly comparable. The difference can be attributed primarily to economic effects; essentially, the January 2009 Load Forecast did not fully account for the effect of the downturn in the regional economy.

Q. WHAT IS THE EFFECT OF THIS DIFFERENCE IN PEAK LOAD?

A. The year-to-year peak load forecast changes in the Mid-Atlantic region vary depending on the forecast years examined, and depending on the forecast vintage used. However, reviewing the PJM January 2007 and PJM January 2008 Load Forecast Reports, the year to year peak load forecast change over ten years is 1.5% per year, or roughly 1,000 MW

24 Available at http://www.pjm.com/planning/resource-adequacy-planning/~/media/planning/res-adeq/load-forcast/summer-2009-pjm-scps-and-w-n-zonal-peaks.ashx.

each year. That is, prior to the economic downturn, PJM expected Mid-Atlantic area peak load to increase roughly 1,000 MW each year. Thus, an updated load forecast alone could shift outward the net peak load of the Mid-Atlantic region by roughly two years, depending on the manner in which the regional economy rebounds. For the purposes of this testimony, I have used the overall PJM peak load in summer 2009 compared to the overall PJM summer peak load forecast from January 2009 to adjust the estimate for peak load in future years.

Q. IF PJM WERE TO UPDATE ITS ANALYSIS TO REFLECT A LOAD FORECAST OF MORE RECENT VINTAGE THAN THE JANUARY 2009 LOAD FORECAST REPORT, WHAT WOULD YOU EXPECT?

A. If PJM updated its analysis using a more current vintage load forecast, due to the extremely unusual economic situation in the nation and the region, the actual peak load differences between those used in PJM model runs (based on the January 2009 PJM Load Forecast) and those that would arise from a current forecast would lead to an outward shift in the net peak load seen in the Mid-Atlantic region of PJM over and above the outward shifts that result from incorporating the demand response and energy efficiency resources noted earlier in this testimony.

Q. IS THERE OTHER EVIDENCE THAT A NEW FORECAST WOULD SHOW LOWER FORECAST PEAK LOAD THAN PJM'S JANUARY 2009 LOAD FORECAST REPORT?

A. Yes. PJM's Mr. Herling testified as to the state of PJM's knowledge in July 2009 that the overall PJM load in 2012 would be 1,004 MW lower than that forecast in the January 2009 Load Forecast Report.[25]

Q. WHAT DO YOU CONCLUDE FROM YOUR EXAMINATION OF PJM MODELING ASSUMPTIONS FOR THE PROPOSED PATH LINE?

A. Based on my examination of PJM modeling assumptions for demand response resources, energy efficiency resources, and peak load forecast I conclude that the exclusion of considerable DR and EE resources made available through the 2012/13 RPM auction; the lack of consideration of additional legislated or policy-initiated state utility demand side initiatives in VA, MD, DC, DE, PA and NJ; and the use of an outdated load forecast all results in a flawed transmission need modeling result.

IV. PEAK LOAD DURATION IN PJM REGIONS AND IMPLICATIONS FOR ALTERNATIVE RELIABILITY RESOURCES

Q. WHAT IS PEAK LOAD DURATION ?

A. Peak load duration is a measure of the amount of time over the course of any particular time interval – e.g, a calendar year, a PJM planning year (June through the following May), or a season – that load in an area reaches relative maximum levels. A "load duration curve" is used to display the frequency of loading level across all hours of a given interval, and represents a visual display of how often load reaches any given threshold level in a region or group of regions. For PJM regions, these patterns are

[25] Rebuttal Testimony of Steven R. Herling, PPL Electric Statement No. 7-R, Before the Pennsylvania Public Utility Commission, Docket No. A-2009-2082652, August 7, 2009, page 8, lines 17-20.

displayed in the figures that follow in this section of my testimony, and I discuss the implications of the peak load durations.

Q. HOW IS A LOAD DURATION CURVE PRODUCED?

A. Hourly data is collected for the region of interest and for the interval of interest. For the purposes of this testimony, I collected hourly data from PJM for the Mid-Atlantic region, and for some of its subregions. The data is sorted in descending order and the resulting data series is graphed to show the pattern of peak load duration. The dates and times of the highest peak loads are noted and tabulated to complete the picture of the pattern of peak loading.

Q. WHY IS PEAK LOAD DURATION IMPORTANT IN THE CONTEXT OF THE ALLEGED NEED FOR THE PROPOSED PATH LINE?

A. The purported need for the PATH line in 2014 is based on forecasted "extreme" peak load levels (in the Mid-Atlantic, and to a lesser degree, the Dominion, region of PJM) used in the load deliverability power flow modeling that underlies the alleged NERC criteria violations listed in applicants' Exhibits PFM-1, PFM-2 and PFM-3. The modeling uses a snapshot of time, representing the modeling of inordinately high stress levels on the transmission system. In its modeling of alleged PATH need, PJM does not consider that such a peak load value, or values close to it, may only occur infrequently throughout the year.

Q. SHOULD THEY CONSIDER THAT?

A. In my opinion, yes, absolutely. PJM should consider it because the economic cost of lowering peak load for a handful of hours each summer through alternatives such as demand response or peaking generation could be lower than the costs of the PATH line. Until a closer examination is made, such a cost comparison cannot be made.

Q. WHAT WOULD BE THE EFFECT OF A LOWER PEAK LOAD?

A. If modeled peak loads in the Mid-Atlantic region, for example, are lower, the stresses seen by the transmission system are lower and any purported "need" for PATH is also lower. Indeed, PJM does lower the forecast peak load by a level of demand side resource in its testing, arriving at a "net" peak load that is purposefully reduced due to the presence of demand-side resources. However, PJM does not sufficiently account for the demand-side resources. The crux of my testimony is that PJM has modeled an unreasonably high "net peak load" in the Mid-Atlantic region.

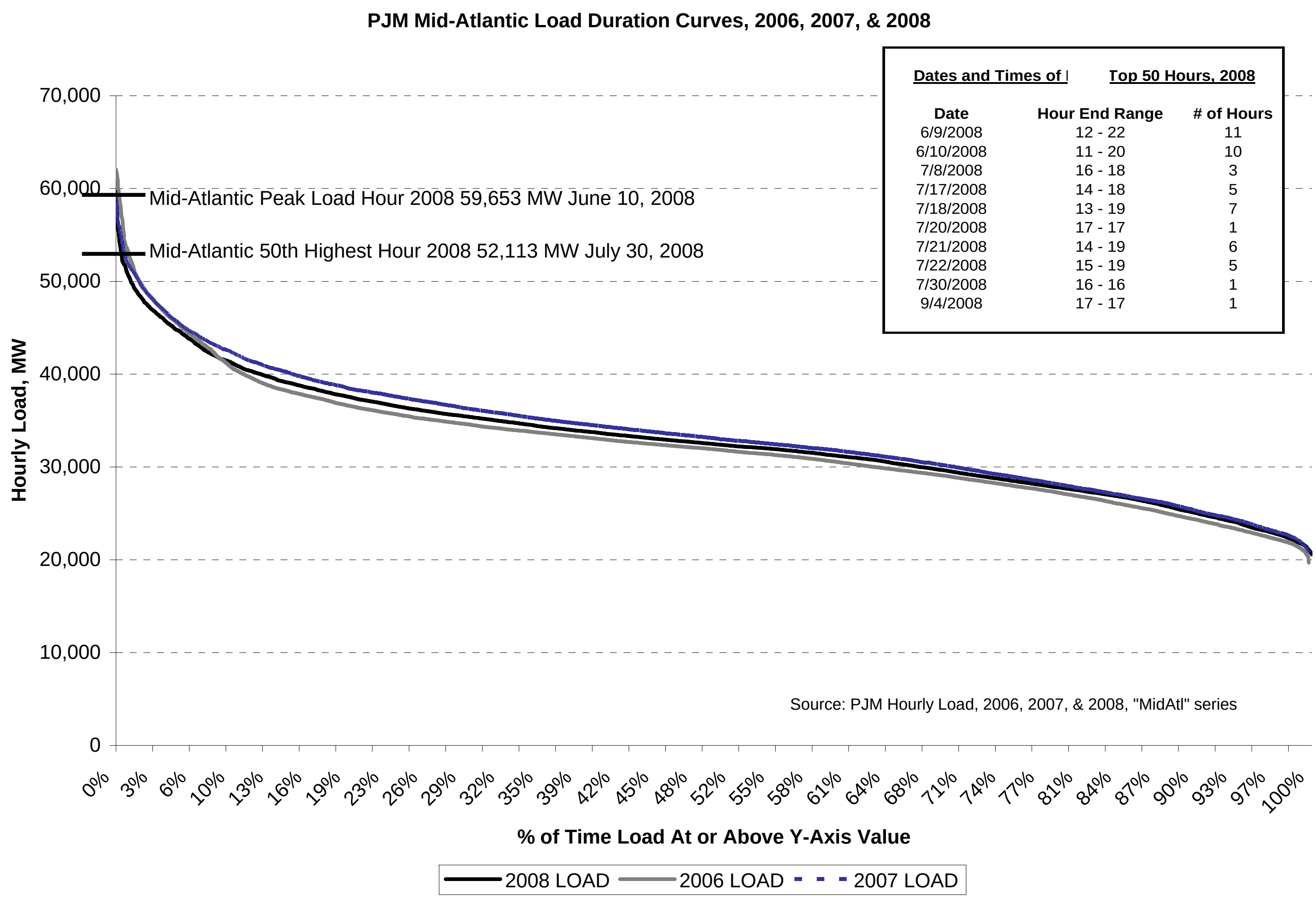
Q. IS IT REASONABLE TO USE LOWER PEAK LOADS IN THIS CASE?

A. Yes. Peak loads seen on the most critical transmission system elements, such as those shown in the "Electrical Result" column of Exhibits PFM-1 and PFM-2, can be lowered through the implementation of energy efficiency improvements, the use of "demand response" or temporary reductions in load, and the use of generation close to load or even "behind the meter" at load sites.

Q. WHAT IS THE PATTERN OF LOAD DURATION, AND HOW OFTEN DOES LOAD REACH PEAK LEVELS, IN PJM?

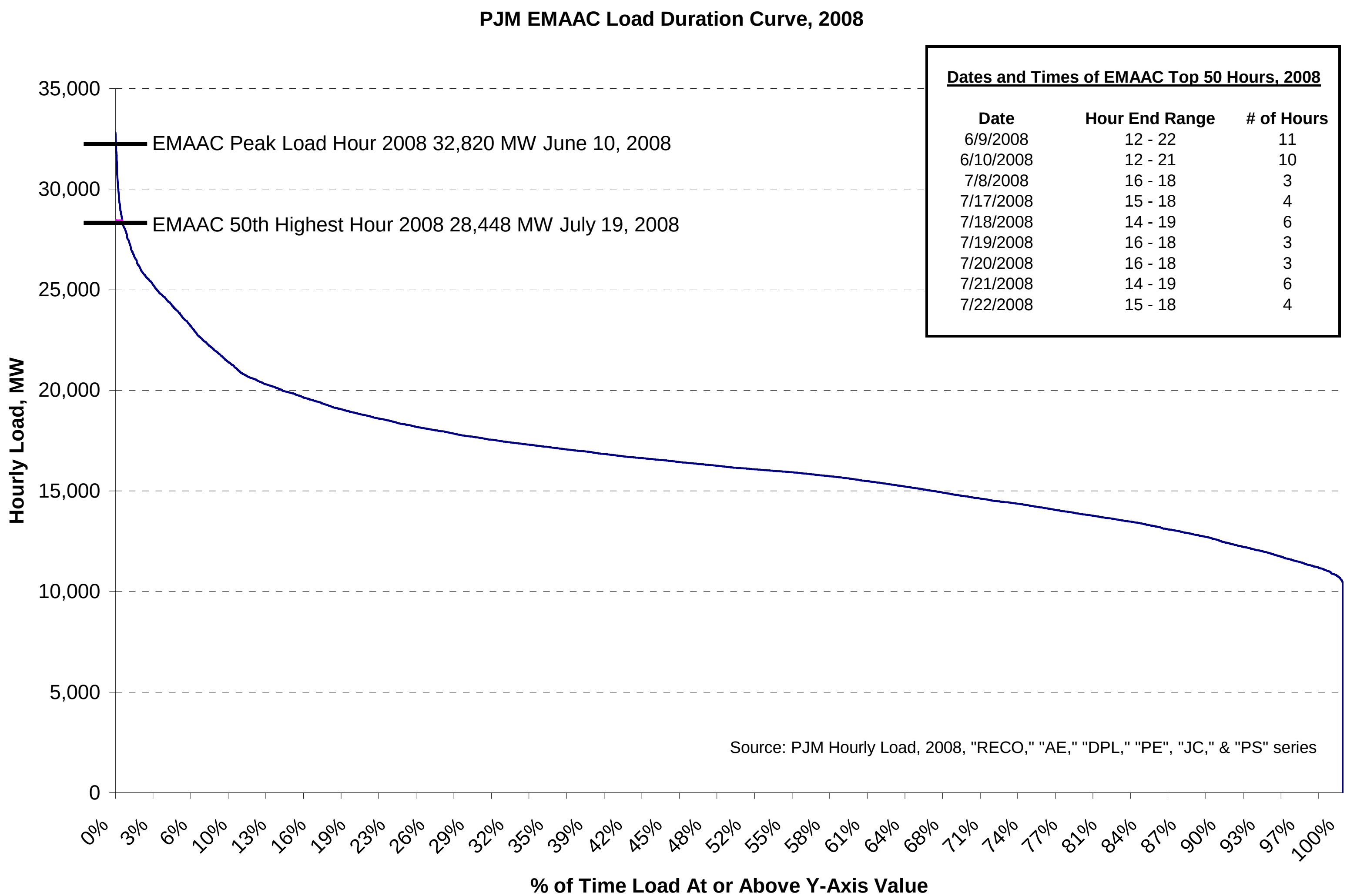
A. Figures 2 through 4 below show load duration curves for three regions of PJM: the Mid-Atlantic ("MAAC"), the eastern portion of the Mid-Atlantic ("EMAAC"), and the service territories of BGE and PEPCO, together known as the Southwest Mid-Atlantic ("SWMAAC"). Each of the curves is of similar shape. The shape indicates that there are a relatively few hours per year over which the peak loading on the system is seen. To demonstrate that load duration patterns do not change appreciably in any given multiple-year period, I include load duration curves for 2006 through 2008 for the Mid-Atlantic region.

Figure 2. PJM MAAC Load Duration Curve, 2008, 2007, 2006 with Dates and Hours for Top 50 Hours of 2008



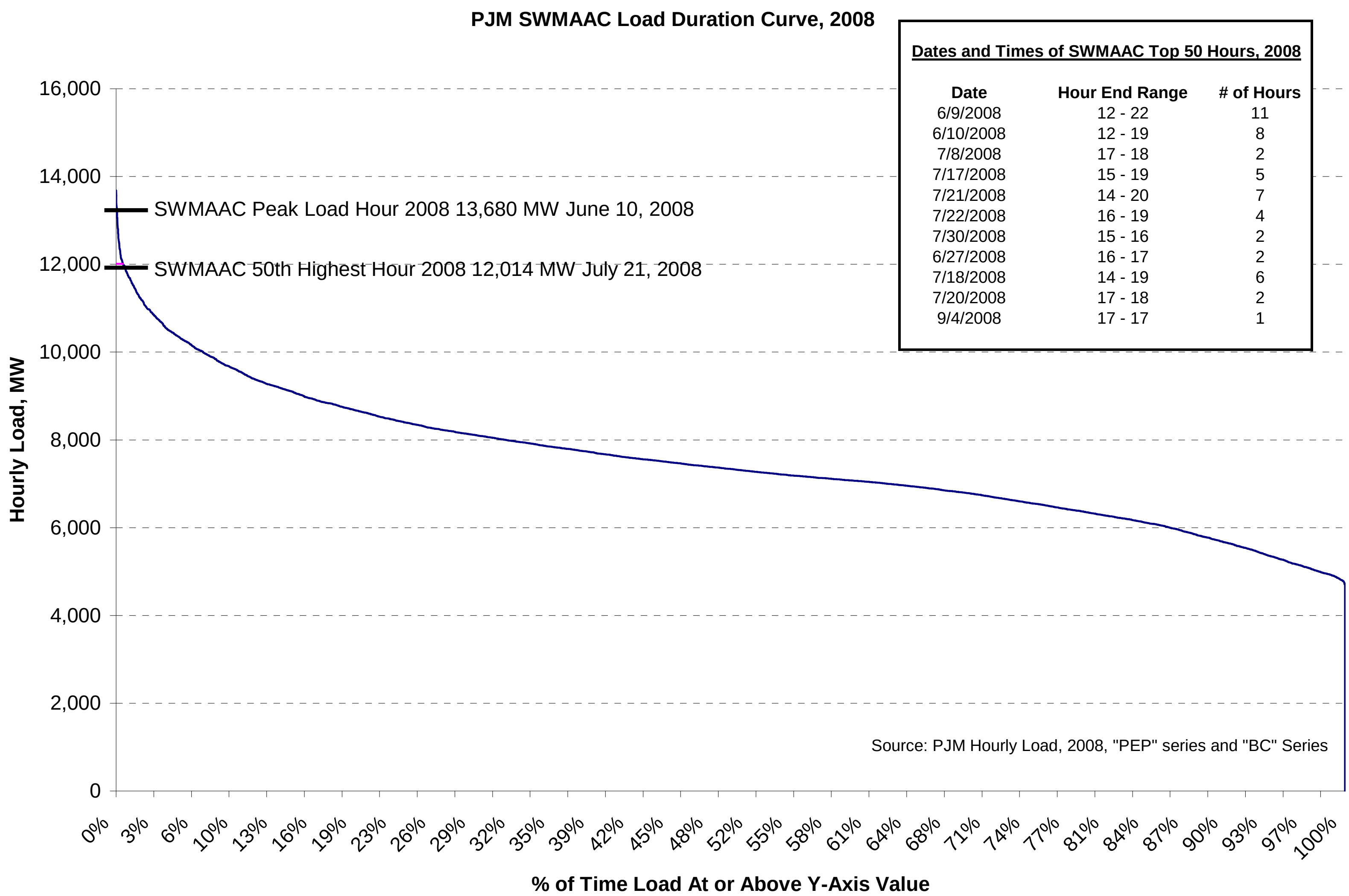
Source: Synapse, from PJM data at http://www.pjm.com/~/media/markets-ops/compliance/historical-load-data/2008-hourly-loads.ashx

Figure 3. PJM Eastern MAAC Load Duration Curve, 2008



Source: Synapse, from PJM data at http://www.pjm.com/~/media/markets-ops/compliance/historical-load-data/2008-hourly-loads.ashx

Figure 4. PJM Southwestern MAAC Load Duration Curve, 2008



Source: Synapse, from PJM data at http://www.pjm.com/~/media/markets-ops/compliance/historical-load-data/2008-hourly-loads.ashx

Q. WHAT DO THESE LOAD DURATION CURVES ILLUSTRATE?

A. The first load duration curve, for the PJM Mid-Atlantic area, shows that the load in the region reached its peak for 2008 at 59,653 MW on June 10. The graph also shows that the highest levels of peak load persist for only a limited amount of time. In this illustration, the "top 50" peak hours of the year (experienced during afternoon hours over the course of ten different days during the summer of 2008) are the only times when load exceeds 52,113 MW. In other words, the last 7,540 MW of peak load (59,653 MW minus 52,113 MW), or the last 13% of incremental peak loading in MAAC in 2008 occurred during just 50 hours, or for only six-tenths of 1% of the year (50/8,784 = 0.57%).

Q. WHAT DO THE OTHER LOAD DURATION CURVES ILLUSTRATE?

A. The other load duration curves, each of which represents a sub-region of the Mid-Atlantic region, confirm that the duration patterns are similar across the region. This is important because demand response and energy efficiency resources that serve to reduce local peak load can also serve to reduce the regional peak load.

Q. THE TITLE OF THIS SUBSECTION REFERENCES "ALTERNATIVE RELIABILITY RESOURCES". WHAT DO YOU MEAN BY "ALTERNATIVE RELIABILITY RESOURCES"?

A. Alternative reliability resources are those resources whose use would defer or eliminate the need for the PATH line to resolve modeled reliability issues. Those resources include generation and demand side resources in the Mid-Atlantic regions of PJM.

Q. HOW WOULD THE USE OF SUCH RESOURCES OFFER AN ALTERNATIVE TO PATH?

A. As can be seen by the load duration curves above, if resources can be used to lower peak demand during the limited hours in the summer period when load reaches its highest levels in these regions of PJM, the transmission system would only have to support delivery of energy to meet the "net peak load" or the peak load that would be seen after accounting for the presence of these resources.

V. GENERATION ASSUMPTIONS

Q. HOW MUCH GENERATION IS IN THE PJM INTERCONNECTION QUEUE IN THE MID-ATLANTIC REGION?

A. Table 10 below shows that in the most recent three PJM-lettered queues[26] - T, U, and V – there exists a total of 12,317 MW of capacity. A majority of this capacity (71%) is natural gas fired. As can be seen, the capacity is distributed across the service territories in the Mid-Atlantic region.

Table 10. Summary of MWC Generation Queued in the Mid-Atlantic Region in Queues T, U, and V

Utility Service Territory	MW of Capacity
AEC	364
BGE	1,887
DPL	87
JCPL	760
ME	1,870
PECO	1,412
PENELEC	128
PEPCO	2,045
PPL	1,689
PSEG	1,948
UGI	126
Mid-Atlantic Total	12,317

Source: PJM interconnection queue data, summarized by Synapse.

26 Earlier queued information from PJM did not have either "status" or "in-service" dates; for the purpose of this section of testimony, I have limited queue data to the T, U and V queues. It is possible that there is even additional Mid-Atlantic queued generation not represented in Table 10 above that could provide capacity to mitigate purported PATH need.

Q. WHAT LEVEL OF NEW MID-ATLANTIC GENERATION RESOURCES DOES PJM USE IN ITS ANALYSES?

A. In response to Sierra VA-IV-55 (Attachment A), PJM indicated that 1,276 MW of Mid-Atlantic region generation was included in its analysis. This amount includes 730 MW that was indicated to be in Area #25, the "PJM 500 kV" region. It is possible that some of this 730 MW of generation is not in the Mid-Atlantic region[27], thus my estimate of 1,276 MW of new generation in the Mid-Atlantic region may be too high.

Q. WHAT DOES THIS INDICATE?

A. It indicates that there is roughly ten times more generation in PJM's last three queues in the Mid-Atlantic region than PJM uses in its modeling of purported need for PATH.

Q. WILL PJM INCLUDE THE PRESENCE OF THE PATH LINE WHEN IT CONDUCTS THE RPM AUCTION FOR CAPACITY FOR 2014/15 IN MAY OF 2011?

A. Yes.

Q. WILL THE PRESENCE OF THE PATH LINE IN THAT MODELING FOR THE 2014/15 RPM AFFECT THE LEVEL OF GENERATION THAT MIGHT CLEAR IN SUCH AN AUCTION?

A. Yes. The presence of the line in the modeling will affect the amount of generation that would otherwise clear in the auction if the line were not modeled as "in-service", and it could also affect the clearing price for capacity resources in the Mid-Atlantic in the auction.

[27] The PJM 500 kV system extends out beyond the Mid-Atlantic region, to the western and southern regions of PJM.

VI. NO ECONOMIC ANALYSES OF PROPOSED PATH LINE OR ALTERNATIVES

Q. HAVE THE APPLICANTS CONDUCTED AN ECONOMIC ANALYSIS OF THE PROPOSED PATH LINE?

A. No.

Q. HAVE THE APPLICANTS CONDUCTED AN ECONOMIC ANALYSIS OF ANY ALTERNATIVES TO THE PROPOSED PATH LINE?

A. No.

Q. HOW MUCH IS THE PROPOSED PATH LINE PROJECTED TO COST?

A. Currently, PATH is projected to cost approximately $1.85 Billion, leading to an annual revenue requirement of $364.7 million by 2014.[28]

Q. IS THERE ANY COMPREHENSIVE DOCUMENTATION OF ENERGY, CAPACITY, OR OTHER SAVINGS FOR RATEPAYERS DUE TO THE PRESENCE OF THE PATH LINE?

A. No. A "market efficiency" analysis conducted by PJM in 2007 illustrated a "change in system load payment" of negative $47.6 million in the year 2013, illustrating that based on the production cost model used by PJM at that time, an estimate of $47.6 million in annual load savings in that year was seen.[29] However, there is no testimony from any of the applicants on, for example, year-by-year or long-term period projections of market savings or economic benefits that might accrue from the proposed PATH line.

Q. WHAT DO YOU CONCLUDE FROM THIS?

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[28] Direct Testimony, Mr. Pokrajac, page 6 and page 14.

[29] Amos-Kemptown market efficiency analysis. Available at http://www.pjm.com/committees-and-groups/committees/teac/~/media/committees-groups/committees/teac/postings/amos-kemptown-765kv.ashx

A. I conclude that the market efficiency analyses conducted by or on behalf of PJM in 2007 illustrate that aggregate annual market savings associated with PATH for the year 2013 was estimated to be an order of magnitude lower than the annual revenue requirements of the line for the first year of operation, i.e., $47 million in savings compared to $365 million in costs. There is no updated analysis accounting for any changes that have taken place since that earlier market efficiency analysis, and there is no analysis that looks at the economics beyond the year 2013. The line is now estimated by PJM to be needed in 2014.

VII. CONCLUSIONS AND RECOMMENDATIONS

Q. WHAT ARE YOUR KEY CONCLUSIONS FROM YOUR ANALYSIS OF THE PROPOSED PATH LINE?

A. 1. In its analysis of transmission reliability that is the foundation for its assertion of PATH need, PJM excludes the peak load reducing effect of 2,908 MW of Mid-Atlatnic region demand response and energy efficiency resources that have already cleared in the PJM May 2009 RPM auction. Incorporating these known capacity resources into the modeling would result in a net peak load in the Mid-Atlantic region of PJM that will not reach the level currently projected to occur in 2014 until 2018.

2. PJM gives no consideration to the additional peak-load reducing effect of energy efficiency and demand response resources that will come from planned initiatives in all of the Mid-Atlantic States and the District of Columbia, pursuant to state law or policy. The electric utility filings and/or utility commission determinations in those states indicate an additional 2,000+ MW of peak load reduction arising from the

implementation of these resources. PJM does not consider even a fraction of these resources when assessing PATH need.

3. The peak load in the PJM Mid-Atlantic region in the summer of 2009 was 57,590 MW, or 2,031 MW lower than PJM's January 2009 forecast load of 59,621 MW. Thus, actual load was 3.4% lower in the summer of 2009 than PJM's January 2009 Load Forecast had estimated.[30] This illustrates that the effect of the downturn in the regional economy in 2009 was significantly greater than PJM had estimated in its load forecast of January 2009.

4. Based on the above three conclusions, I broadly conclude that PJM has used unreasonable modeling assumptions in support of its assertion of PATH need, and thus the results of its modeling are flawed.

5. PJM has not analyzed demand-side or generation alternatives to PATH that address the very short duration of the peak load level that is a primary driver of the purported need for PATH. PJM has not conducted any economic analysis to determine if options other than the proposed PATH line could be the lower cost choice to resolve reliability concerns.

Q. WHAT DO YOU RECOMMEND?

A. My primary recommendation is that the Virginia State Corporation Commission deny the application outright due to the unsupported assertions of need for the proposed PATH line. Alternatively, at a minimum the applicants must re-analyze the alleged need for PATH using current, reasonable input assumptions for demand-side resources and forecast peak load. Such assumptions should clearly include the results of the May 2009

30 The load value stated for the summer 2009 Mid-Atlantic region is a "weather normalized" coincident peak, and thus is directly comparable to the 50/50 (i.e., weather normalized) peak load forecast in January 2009 for the Mid-Atlantic region.

RPM auction and the demand-side resources made available by that auction, and should also recognize the contribution to peak load reduction that will arise from the state level initiatives identified and described in this testimony. The assumptions should also include a current peak load forecast. As part of any such required re-examination of alleged PATH need, the applicants should analyze alternative reliability solutions and should conduct a full economic assessment of the effect on PJM ratepayers of the different alternatives.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Exhibit RMF-1

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SUMMARY

Mechanical engineer and energy economics analyst with over 20 years experience in the energy industry. Activities focused primarily on electric power industry issues, especially economic and technical analysis of transmission pricing structures, wholesale electricity markets, renewable resource alternatives and assessment and implementation of demand-side alternatives.

In-depth understanding of the complexities of, and the interrelationships between, the technical and economic dimensions of the electric power industry in the US and Canada, including the following areas of expertise:

- Wholesale energy and capacity provision under market-based and regulated structures; the extent of competitiveness of such structures.
- Potential for and operational effects of wind power integration into utility systems.
- Transmission use pricing, encompassing congestion management, losses, LMP and alternatives, financial and physical transmission rights; and transmission asset pricing (embedded cost recovery tariffs).
- Physical transmission network characteristics; related generation dispatch/system operation functions; and technical and economic attributes of generation resources.
- RTO and ISO tariff and market rules structures and operation.
- FERC regulatory policies and initiatives, including those pertaining to RTO and ISO development and evolution.
- Demand-side management, including program implementation and evaluation; and load response presence in wholesale markets.
- Building energy end-use characteristics, and energy-efficient technology options.
- Fundamentals of electric distribution systems and substation layout and operation.
- Energy modeling (spreadsheet-based, GE MAPS and online DOE-2 residential).
- State and provincial level regulatory policies and practices, including retail service and standard offer pricing structures.
- Gas industry fundamentals including regulatory and market structures, and physical infrastructure.

PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Inc., Cambridge, MA. 2004 – Present. Senior Associate
Responsibilities include consulting on issues of energy economics, analysis of electricity utility planning, operation, and regulation, including issues of transmission, generation, and demand-side management. Provide expert witness testimony on various wholesale and retail electricity industry issues. Specific project experience includes the following:

- Analysis of need for transmission facilities in Maine and Ontario.
- Ongoing analysis of wholesale and retail energy and capacity market issues in New Jersey, including assessment of BGS supply alternatives and demand response options.
- Analysis of PJM transmission-related issues, including cost allocation, need for new facilities and PJM's economic modeling of new transmission effects on PJM energy market.
- Ongoing analysis of utility-sponsored energy efficiency programs in Rhode Island as part of the Rhode Island DSM Collaborative.
- Analysis of proposals in Maine for utility companies to withdraw from the ISO-NE RTO.
- Analysis of utility planning and demand-side management issues in Delaware.
- Analysis of effect of increasing the system benefits charge (SBC) in Maine to increase procurement of energy efficiency and DSM resources; analysis of impact of DSM on transmission and distribution reinforcement need.
- Evaluation of wind energy potential and economics, related transmission issues, and resource planning in Minnesota, Iowa, Indiana, and Missouri; in particular in relation to alternatives to newly proposed coal-fired power plants in MN, IA and IN.
- Analysis of need for newly proposed transmission in Pennsylvania and Ontario.
- Evaluation of wind energy "firming" premium in BC Hydro Energy Call in British Columbia.
- Evaluation of pollutant emission reduction plans and the introduction of an open access transmission tariff in Nova Scotia.
- Evaluation of the merger of Duke and Cinergy with respect to Indiana ratepayer impacts.
- Review of the termination of a Joint Generation Dispatch Agreement between sister companies of Cinergy.
- Assessment of the potential for an interstate transfer of a DSM resource between the desert southwest and California, and the transmission system impacts associated with the resource.
- Analysis of various transmission system and market power issues associated with the proposed Exelon-PSEG merger.
- Assessment of market power and transmission issues associated with the proposed use of an auction mechanism to supply standard offer power to ComEd native load customers.
- Review and analysis of the impacts of a proposed second 345 kV tie to New Brunswick from Maine on northern Maine customers.

Tabors Caramanis & Associates, Cambridge, MA 1996 -2004. Senior Associate.

- Provided expert witness testimony on transmission issues in Ontario and Alberta.

- Supported FERC-filed testimony of Dr. Tabors in numerous dockets, addressing various electric transmission and wholesale market issues.
- Analyzed transmission pricing and access policies, and electric industry restructuring proposals in US and Canadian jurisdictions including Ontario, Alberta, PJM, New York, New England, California, ERCOT, and the Midwest. Evaluated and offered alternatives for congestion management methods and wholesale electric market design.
- Attended RTO/ISO meetings, and monitored and reported on continuing developments in the New England and PJM electricity markets. Consulted on New England FTR auction and ARR allocation schemes.
- Evaluated all facets of Ontario and Alberta wholesale market development and evolution since 1997. Offered congestion management, transmission, cross-border interchange, and energy and capacity market design options. Directly participated in the Ontario Market Design Committee process. Served on the Ontario Wholesale Market Design technical panel.
- Member of TCA GE MAPS modeling team in LMP price forecasting projects.
- Assessed different aspects of the broad competitive market development themes presented in the US FERC's SMD NOPR and the application of FERC's Order 2000 on RTO development.
- Reviewed utility merger savings benchmarks, evaluated status of utility generation market power, and provided technical support underlying the analysis of competitive wholesale electricity markets in major US regions.
- Conducted life-cycle utility cost analyses for proposed new and renovated residential housing at US military bases. Compared life-cycle utility cost options for large educational and medical campuses.
- Evaluated innovative DSM competitive procurement program utilizing performance-based contracting.

Charles River Associates, Boston, MA, 1992-1996. **Associate**. Developed DSM competitive procurement RFPs and evaluation plans, and performed DSM process and impact evaluations. Conducted quantitative studies examining electric utility mergers; and examined generation capacity concentration and transmission interconnections throughout the US. Analyzed natural gas and petroleum industry economic issues; and provided regulatory testimony support to CRA staff in proceedings before the US FERC and various state utility regulatory commissions.

Rhode Islanders Saving Energy, Providence, RI, 1987-1992. **Senior Commercial/Industrial Energy Specialist**. Performed site visits, analyzed end-use energy consumption and calculated energy-efficiency improvement potential in approximately 1,000 commercial, industrial, and institutional buildings throughout Rhode Island, including assessment of lighting, HVAC, hot water, building shell, refrigeration and industrial process systems. Recommended and assisted in implementation of energy efficiency measures, and coordinated customer participation in utility DSM program efforts.

Fairchild Weston Systems, Inc., Syosset, NY 1985-1986. Facilities Engineer. Designed space renovations; managed capital improvement projects; and supervised contractors in implementation of facility upgrades.

Narragansett Electric Company, Providence RI, 1981-1984. Supervisor of Operations and Maintenance. Directed electricians in operation, maintenance, and repair of high-voltage transmission and distribution substation equipment.

EDUCATION

Boston University, M.A. Energy and Environmental Studies, 1992
Resource Economics, Ecological Economics, Econometric Modeling

Clarkson University, B.S. Mechanical Engineering, 1981
Thermal Sciences

Additional Professional Training and Academic Coursework
Utility Wind Integration Group - Short Course on Integration and Interconnection of Wind Power Plants Into Electric Power Systems (2006).
Regulatory and Legal Aspects of Electric Power Systems – Short Course – University of Texas at Austin (1998)
Illuminating Engineering Society courses in lighting design (1989).
Coursework in Solar Engineering; Building System Controls; and Cogeneration at Worcester Polytechnic Institute and Northeastern University (1984, 1988-89).
Graduate Coursework in Mechanical and Aerospace Engineering – Polytechnic Institute of New York (1985-1986)

SUMMARY OF TESTIMONY, PUBLICATIONS, AND PRESENTATIONS

TESTIMONY

Pennsylvania Public Utility Commission. Direct and Surrebuttal testimony filed before the Commission on the need for the proposed Susquehanna-Roseland 500 kV Line. Docket No. A-2009-2082652 *et al*. Direct Testimony filed June 30, 2009; Surrebuttal Testimony filed August 24, 2009.

Delaware Public Service Commission. Report on Behalf of the Staff of the Delaware Public Service Commission, filed in Docket No. 07-20, Delmarva's IRP docket, "Review of Delmarva Power & Light Company's Integrated Resource Plan", April 2, 2009. Jointly authored with Alice Napoleon, William Steinhurst, David White, and Kenji Takahashi of Synapse Energy Economics. Hearings scheduled for July 2009.

State of Maine Public Utilities Commission. Pre-filed Direct Testimony on the Application of Central Maine Power for a Certificate of Public Convenience and Necessity for the proposed Maine Power Reliability Project (MPRP), a $1.55 billion transmission enhancement project. Testimony focus on the non-transmission alternatives analysis conducted on behalf of CMP.

Maine PUC Docket 2008-255, filed January 12, 2009 on behalf of the Maine Office of Public Advocate. Docket proceeding; no hearings to date.

New Jersey Board of Public Utilities. Oral testimony before the Board, jointly with Bruce Biewald, on certain aspects of the Basic Generation Service (BGS) procurement plan for service beginning June 1, 2009. Docket No. ER08050310. Hearing conducted on September 29, 2008.

Wisconsin Public Service Commission. Direct and Surrebuttal Testimony in Docket 6680-CE-170 on behalf of Clean Wisconsin in the matter of an application by Wisconsin Power and Light for a CPCN for construction of a 300 MW coal plant. The testimony focused on the alternative energy options available with wind power, and the effect of the MISO RTO in helping provide capacity and energy to the Wisconsin area reliably without needed the proposed coal plant. The CPCN was denied by the WPSC in December 2008. Testimony filed in August (Direct) and September (Surrebuttal), 2008.

Ontario Energy Board. Pre-Filed Direct Testimony filed on behalf of Pollution Probe in the matter of the Examination and Critique of Demand Response and Combined Heat and Power Aspects of the Ontario Power Authority's Integrated Power System Plan and Procurement Process, Docket EB-2007-0707. The testimony addressed issues associated with the planned levels of procurement of demand response, combined heat and power, and NUG resources as part of Ontario Power Authority's long-term integrated planning process. Testimony filed on August 1, 2008. Docket is open; additional Power System Plan and Procurement filings expected from the Ontario Power Authority.

Ontario Energy Board. Direct and Supplemental Testimony filed jointly with Mr. Peter Lanzalotta on behalf of Pollution Probe in the matter of Hydro One Networks Inc. application to construct a new 500 kV transmission line between the Bruce Power complex and the town of Milton, Ontario. Docket EB-2007-0050. The testimony addressed issues of congestion (locked-in energy) modeling, need, and series compensation and generation rejection alternatives to the proposed line. Testimony filed on April 18, 2008 (Direct) and May 15, 2008 (Supplemental).

Federal Energy Regulatory Commission. Direct and Rebuttal Testimony on PJM Regional Transmission Expansion Plan (RTEP) Cost Allocation issues in Dockets ER06-456, ER06-954, ER06-1271, ER07-424, EL07-57, ER06-880, et al. The testimony addressed merchant transmission cost allocation issues. Testimony filed on behalf of the New Jersey Department of the Public Advocate, Ratepayer Division. Testimony filed on January 23, 2008 (Direct) and April 16, 2008 (Rebuttal).

Minnesota Public Utilities Commission. Supplemental Testimony and Supplemental Rebuttal Testimony on applicants' estimates of DSM savings in the Certificate of Need proceeding for the Big Stone II coal-fired power plant proposal. In the Matter of the Application by Otter Tail Power Company and Others for Certification of Transmission Facilities in Western Minnesota and In the Matter of the Application to the Minnesota Public Utilities Commission for a Route Permit for the Big Stone Transmission Project in Western Minnesota. OAH No. 12-2500-17037-2 and OAH No. 12-2500-17038-2; and MPUC Dkt. Nos. CN-05-619 and TR-05-1275.

Testimony filed December 21, 2007 (Supplemental) and January 16, 2008 (Supplemental Rebuttal).

Pennsylvania Public Utility Commission. Direct testimony filed before the Commission on the effect of demand-side management on the need for a transmission line and the level of consideration of potential carbon regulation on PJM's analysis of need for the TrAIL transmission line. Docket Nos. A-110172 *et al*. Testimony filed October 31, 2007.

Iowa Public Utilities Board. Direct testimony filed before the Board on wind energy assessment in Interstate Power and Light's resource plans and its relationship to a proposed coal plant in Iowa. Docket No. GCU-07-01. Testimony filed October 21, 2007.

New Jersey Board of Public Utilities. Direct testimony before the Board on certain aspects of PSE&G's proposal to use ratepayer funding to finance a solar photovoltaic panel initiative in support of the State's solar RPS. Docket No. EO07040278. Testimony filed September 21, 2007.

Indiana Utility Regulatory Commission. Direct Testimony filed before the Commission addressing a proposed Duke – Vectren IGCC coal plant. Testimony focused on wind power potential in Indiana. Filed on behalf of the Citizens Action Coalition of Indiana, Cause No. 43114 May 14, 2007.

State of Maine Public Utilities Commission. Pre-filed testimony on the ability of DSM and distributed generation potential to reduce local supply area reinforcement needs. Testimony filed before the Commission on a Request for Certificate of Public Convenience and Necessity to Build a 115 kV Transmission Line between Saco and Old Orchard Beach. Testimony filed jointly with Peter Lanzalotta, on behalf of the Maine Public Advocate. Docket No. 2006-487, February 27, 2007.

Minnesota Public Utilities Commission. Rebuttal Testimony on wind energy potential and related transmission issues in the Certificate of Need proceeding for the Big Stone II coal-fired power plant proposal. In the Matter of the Application by Otter Tail Power Company and Others for Certification of Transmission Facilities in Western Minnesota and In the Matter of the Application to the Minnesota Public Utilities Commission for a Route Permit for the Big Stone Transmission Project in Western Minnesota. OAH No. 12-2500-17037-2 and OAH No. 12-2500-17038-2; and MPUC Dkt. Nos. CN-05-619 and TR-05-1275. December 8, 2006.

British Columbia Utilities Commission. In the Matter of BC Hydro 2006 Integrated Electricity Plan and Long Term Acquisition Plan. Pre-filed Evidence filed on behalf of the Sierra Club (BC Chapter), Sustainable Energy Association of BC, and Peace Valley Environment Association. October 6, 2006. Testimony addressing the "firming premium" associated with 2006 Call energy, liquidated damages provisions, and wind integration studies.

Maine Joint Legislative Committee on Utilities, Energy and Transportation. Testimony before the Committee in support of an Act to Encourage Energy Efficiency (LD 1931) on behalf of the Maine Natural Resources Council, February 9, 2006. The testimony and related analysis focused on the costs and benefits of increasing the system benefits charge to increase the level of energy efficiency installations by Efficiency Maine.

Nova Scotia Utilities and Review Board (UARB). Testimony filed before the UARB on behalf of the UARB staff, In The Matter of an Application by Nova Scotia Power Inc. for Approval of Air Emissions Strategy Capital Projects. Filed Jaunary 30, 2006. The testimony addressed the application for approval of installation of a flue gas desulphurization system at NSPI's Lingan station and a review of alternatives to comply with provincial emission regulations.

New Jersey Board of Public Utilities. Direct and Surrebuttal Testimony filed before the Commission addressing the Joint Petition Of Public Service Electric and Gas Company And Exelon Corporation For Approval of a Change in Control Of Public Service Electric and Gas Company And Related Authorizations (the proposed merger), BPU Docket EM05020106. Joint Testimony with Bruce Biewald and David Schlissel. Filed on behalf of the New Jersey Division of the Ratepayer Advocate, November 14, 2005 (direct) and December 27, 2005 (surrebuttal).

Indiana Utility Regulatory Commission. Direct Testimony filed before the Commission addressing the proposed Duke – Cinergy merger. Filed on behalf of the Citizens Action Coalition of Indiana, Cause No. 42873, November 8, 2005.

Illinois Commerce Commission. Direct and Rebuttal Testimony filed before the Commission addressing wholesale market aspects of Ameren's proposed competitive procurement auction (CPA). Testimony filed on behalf of the Illinois Citizens Utility Board in Dockets 05-0160, 05-0161, 05-0162. Direct Testimony filed June 15, 2005; Rebuttal Testimony filed August 10, 2005.

Illinois Commerce Commission. Direct and Rebuttal Testimony filed before the Commission addressing wholesale market aspects of Commonwealth Edison's proposed BUS (Basic Utility Service) competitive auction procurement. Testimony filed on behalf of the Illinois Citizens Utility Board and the Cook County State's Attorney's Office in Docket 05-0159. Direct Testimony filed June 8, 2005; Rebuttal Testimony filed August 3, 2005.

Indiana Utility Regulatory Commission. Responsive Testimony filed before the Commission addressing a proposed Settlement Agreement between PSI and other parties in respect of issues surrounding the Joint Generation Dispatch Agreement in place between PSI and CG&E. Filed on behalf of the Citizens Action Coalition of Indiana, Consolidated Causes No. 38707 FAC 61S1, 41954, and 42359-S1, August 31, 2005.

Indiana Utility Regulatory Commission. Direct Testimony filed before the Commission in a Fuel Adjustment Clause (FAC) Proceeding concerning the pricing aspects and merits of continuation of the Joint Generation Dispatch Agreement in place between PSI and CG&E, and related issues of PSI lost revenues from inter-company energy pricing policies. Filed on behalf of the Citizens Action Coalition of Indiana, Cause No. 38707 FAC 61S1, May 23, 2005.

Indiana Utility Regulatory Commission. Direct Testimony filed before the Commission concerning the pricing aspects and merits of continuation of the Joint Generation Dispatch

Agreement in place between PSI and CG&E. Filed on behalf of the Citizens Action Coalition of Indiana, Cause No. 41954, April 21, 2005.

State of Maine Public Utilities Commission. Testimony filed before the Commission on an Analysis of Eastern Maine Electric Cooperative, Inc.'s Petition for a Finding of Public Convenience and Necessity to Purchase 15 MW of Transmission Capacity from New Brunswick Power and for Related Approvals. Testimony filed jointly with David Schlissel and Peter Lanzalotta, on behalf of the Maine Public Advocate. Docket No. 2005-17, July 19, 2005.

State of Maine Public Utilities Commission. Testimony filed before the Commission on an Analysis of Maine Public Service Company Request for a Certificate of Public Convenience and Necessity to Purchase 35 MW of Transmission Capacity from New Brunswick Power. Testimony filed jointly with David Schlissel and Peter Lanzalotta, on behalf of the Maine Public Advocate. Docket No. 2004-538 Phase II, April 14, 2005.

Nova Scotia Utilities and Review Board (UARB). Testimony filed before the UARB on behalf of the UARB staff, In The Matter of an Application by Nova Scotia Power Inc. for Approval of an Open Access Transmission Tariff (OATT). Filed April 5, 2005. The testimony addressed various aspects of OATTs and FERC's *pro forma* Order 888 OATT.

Texas Public Utilities Commission. Testimony filed before the Texas PUC in Docket No. 30485 on behalf of the Gulf Coast Coalition of Cities on CenterPoint Energy Houston Electric, LLC. Application for a Financing Order, January 7, 2005. The testimony addressed excess mitigation credits associated with CenterPoint's stranded cost recovery.

Ontario Energy Board. Testimony filed before the Ontario Energy Board, RP-2002-0120, et al., Review of the Transmission System Code (TSC) and Related Matters, Detailed Submission to the Ontario Energy Board in Response To Phase I Questions Concerning the Transmission System Code and Related Matters, October 31, 2002, on behalf of TransAlta Corporation; and Reply Comments for same, November 21, 2002. Related direct and reply filings in response to the Ontario Energy Board's "Preliminary Propositions" on TSC issues in May and June, 2003.

Alberta Energy and Utilities Board. Testimony filed before the Alberta Energy and Utilities Board, in the Matter of the Transmission Administrator's 2001 Phase I and Phase II General Rate Application, no. 2000135, pertaining to Supply Transmission Service charge proposals. Joint testimony filed with Dr. Richard D. Tabors. March 28, 2001. Testimony filed on behalf of the Alberta Buyers Coalition.

Ontario Energy Board. Testimony filed before the Ontario Energy Board, RP-1999-0044, Critique of Ontario Hydro Networks Company's Transmission Tariff Proposal and Proposal for Alternative Rate Design, January 17, 2000. Testimony filed on behalf of the Independent Power Producer's Society of Ontario.

MAJOR PROJECT WORK – BY CATEGORY

Electric Utility Industry Regulatory and Legislative Proceedings

For Pollution Probe, analysis of need for a proposed 500 kV transmission line in Ontario. (2008)

For the Iowa Office of Consumer Advocate, testimony in the case against the proposed Marshalltown coal plant expansion, addressing the ability of wind resources to help eliminate the need for the plant. (2007-2008)

For the Minnesota Center for Environmental Advocacy, preparation of expert testimony on wind energy and DSM in Minnesota and the upper Midwest in the case against the proposed Big Stone II coal plant. (2006-2008)

For the New Jersey Department of the Ratepayer advocate, ongoing analysis of myriad issues affecting New Jersey electricity consumers, including: review of BGS supply structures, participation in working group designing demand side response pilot programs, analysis of PSE&G solar PV initiatives, review of ongoing FERC proceedings on PJM transmission planning and impacts on New Jersey. (2007-2008)

For the Citizens Action Coalition of Indiana, analyzed the potential for increased wind penetration as an alternative to a proposed new coal-fired power plant. (2007)

For the Maine Office of Public Advocate, technical review of issues pertaining to potential withdrawal of Maine utilities from the ISO NE RTO. Also, technical review and expert testimony preparation on energy efficiency and demand side response resource impact on sub-transmission supply needs in the Saco Bay area. (2006-2007)

For the staff of the Nova Scotia Utility and Review Board, conducted an economic analysis of the proposed installation of flue gas desulphurization equipment by Nova Scotia Power, Inc., and alternatives to the installation, to conform to Nova Scotia provincial emission regulations. (2005-2006)

For the staff of the Nova Scotia Utility and Review Board, analyzed a proposed Open Access Transmission Tariff by Nova Scotia Power, Inc. (2005)

For the Maine Office of Public Advocate, analyzed multiple aspects of the proposed installation of a second 345 kV tie line between Maine and New Brunswick. The analyses focused on the impacts to Northern Maine electric consumers. (2005)

Electric Utility Industry Restructuring

For the Citizens Action Coalition of Indiana, analyzed the proposed merger between Duke and Cinergy, with a focus on global protections available for PSI ratepayers and the allocation of projected merger cost and savings. (2005)

For the Citizens Action Coalition of Indiana, analyzed the termination of the Joint Generation Dispatch Agreement between Cincinnati Gas and Electric and PSI with a focus on PSI ratepayer impacts. (2005)

For TransAlta Energy Corporation, developed an issues and information paper on recent Ontario and Alberta market development efforts, focusing on the likely high-level impacts associated with day-ahead and capacity market mechanisms considered in each of those regions. (2004)

For a wholesale energy market stakeholder, participate in New England and PJM RTO markets and market implementation committee meetings, review and summarize material, and advocate on behalf of client on selected market design issues. (2004) Performed similar activities for separate client in New England. (2001)

For a group of potential generation investors in Ontario, analyzed the government's proposed wholesale and retail market design changes and produced an advocacy report for submission to the Ontario Ministry of Energy. The report emphasized, among other things, the importance of retaining a competitive wholesale market structure. (2004)

For a large midwestern utility, supported multiple rounds of direct and rebuttal testimony to the US FERC by Dr. Richard Tabors on the proposed start-up of LMP markets in the Midwest ISO utility service territories. Testimony substance included PJM-MISO seams concerns, FTR allocation options, grandfathered transactions incorporation, FTR and energy market efficiency impacts, and other wholesale market and MISO transmission tariff design issues. Testimony also included quantitative analysis using GE MAPS security-constrained dispatch model runs. (2003-2004)

For the Independent Power Producers Society of Ontario, with TCA Director Seabron Adamson, developed a position paper on resource adequacy mechanisms for the Ontario electricity market. (2003)

For TransAlta Energy Corp., provided direct and reply testimony to the Ontario Energy Board on the Transmission System Code review process. Analyzed and reported on transmission "bypass" and network cost responsibility issues. (2002-2003)

For a commercial electricity marketer in Ontario, with TCA staff, analyzed Ontario market rules for interregional transactions, focusing primarily on the Michigan and New York interties, and assessed the current Ontario electricity market policy related to "failed intertie transactions". (2002)

For ESBI Alberta Ltd., then Transmission Administrator (TA) of Alberta, served as a key member of the TCA team exploring congestion management issues in the Province, and providing guidance to the TA in presenting congestion management options to Alberta stakeholders, with a particular focus on new transmission expansion pricing and cost allocation issues. (2001)

For a coalition of power producers and marketers in Alberta, filed joint expert witness testimony with Dr. Tabors on the nature of certain transmission access charges associated with supply transmission service. (2001)

For a prospective market participant, served as a core member of the project team that developed summary reports on the New York, New England and PJM wholesale electricity spot market structures. The reports focused on market structure fundamentals, historical transmission flow patterns, forecasted transmission congestion and costs, transmission availability and FTR valuation and market results. (2001)

For the ERCOT ISO, served as a key TCA team member helping to develop and assemble a set of protocols to guide the principles, operation and settlement of the forthcoming Texas competitive wholesale electricity market. (2000)

For the Independent Power Producer's Society of Ontario, served as expert witness and filed evidence with the Ontario Energy Board supporting an alternative transmission tariff design, and critiquing Ontario Hydro Networks Company's (OHNC) proposed rate structure. Also a member of OHNC's Advisory Team on net versus gross billing issues and a leading proponent of a progressive, embedded-generation-friendly tariff structure. (1999-2000)

For a large midwestern utility, designed transmission tariff and wholesale market structures consistent with the proposed establishment of an Independent Transmission Company paradigm for transmission operations. (1999-2000)

For a coalition of independent power producers and marketers in Alberta, helped develop evidence submitted by Dr. Tabors and Dr. Steven Stoft with the Alberta Energy and Utilities Board supporting an alternative to ESBI's proposed transmission tariff. The evidence critiqued the fairness and efficiency of ESBI's proposed tariff, and offered a simple alternative to deal with Alberta's near-term southern supply shortage. (1999)

For Enron Canada Corp., provided ongoing technical support and policy advice during the tenure of the Ontario Market Design Committee (MDC). Presented material on congestion pricing before the committee, and submitted technical assessments of most wholesale market development issues. (1998-1999)

Member of the Ontario Wholesale Market Design Technical Panel. The panel's responsibilities included refinement of the wholesale market design as specified by the Market Design Committee, and specification of the market's initial operating requirements. Also served on two sub-panels: bidding and scheduling; and ancillary services. (1998-1999)

For Enron Canada Corp, assessed the generation markets in Ontario and Alberta and recommended policies for maximizing competitive market mechanisms and minimizing stranded cost burdens. Authored reports on stranded costs in Ontario, and on the legislated hedges structure in Alberta. (1997 - 1998)

For an independent power producer, assessed New England markets for electricity and assisted in valuation of generation assets for sale. (1997)

In support of testimony filed by CCEM (Coalition for Competitive Electric Markets) with the FERC, assessed alternative transmission pricing and wholesale market structures proposed for the NY, NE and PJM regions. The filings proposed market mechanisms to produce competitive wholesale electric energy markets and zonal-based transmission pricing structures. (1996-1997)

Electric Utility Mergers and Market Power Analysis

For the New Jersey Ratepayer Advocate, provided jointly sponsored expert testimony (with Bruce Biewald and David Schlissel) on the potential market power effects of the proposed Exelon-PSEG merger. (2005-2006)

For the Citizens Utility Board (Illinois), provided direct and rebuttal testimony on potential market power and transmission impacts and other issues associated with ComEd’s proposal to procure standard offer power through a market-based auction process. (2005)

For the Citizens Utility Board and other clients (Illinois), provided direct and rebuttal testimony on issues associated with Ameren’s proposal to procure standard offer power through a market-based auction process. (2005)

In support of FERC-filed testimony by Dr. Richard Tabors, conducted a detailed examination of the accessibility of transmission service for wholesale energy market participants on the American Electric Power and Central and Southwest transmission systems. This included evaluating all transmission service requests made over the OASIS for the first six months of 1998 for the two utility systems, and a subsequent, more detailed assessment of AEP’s transmission system use during all of 1998. (1998-1999)

For a US western electric utility, served as a member of the team that conducted detailed production cost modeling and strategic market assessment to determine the extent or absence of market power held by the client. (1998)

For an independent power producer, supported FERC-filed testimony on market power issues in the New York State energy and capacity markets. This included detailed supply-curve assessment of existing generation assets within the New York Power Pool. (1997)

Worked with a local economic consulting firm for a Western State public agency in conducting an analysis of the projected savings of a series of proposed electric and gas utility mergers. (1997)

For a southwestern utility company, supported CRA in conducting an analysis of the competitive effects of a proposed electric utility merger. For a northwestern utility company, analyzed the competitive effects of a proposed electric utility merger. (1995-1996)

For the Massachusetts Attorney General's Office, conducted a study of the potential for market power abuse by generators in the NEPOOL market area. (1996)

Energy Efficiency and Demand Side Management

For the Pennsylvania Office of Consumer Advocate, analysis of the ability of demand-side management efforts to reduce peak loading and affect the need for the 502 Junction – Prexy 500 kV line proposed by Allegheny Power. (2007 – 2008)

For the New Jersey Division of Rate Counsel, Department of Public Advocate, participation in demand response working group and assessment of proposal for state-sponsored demand response program. (2007)

For the Rhode Island Division of the Public Utilities Commission, ongoing technical support and participation in the statewide DSM collaborative process. (2007)

For the Maine Office of the Public Advocate, evaluated the ability of DSM and distributed generation to affect the need for transmission and distribution system reinforcement in the Saco Bay area of Central Maine Power's service territory. (2007)

For the Natural Resources Council of Maine, analyzed the costs and benefits of increasing the system benefits charge (SBC) in Maine to increase efficiency installations by Efficiency Maine. Testimony before the Maine Joint Legislative Committee on Energy and Utilities. (2006)

For Southern California Edison (SCE), working as a sub-contractor to Sargent and Lundy, analyzed the potential for an interstate transfer of a DSM resource between the desert southwest and California. For the same project, also analyzed transmission impacts of various alternatives to replace power supply from the currently closed Mohave generation station for SCE. (2005)

For two separate large New England utilities, conducted impact evaluations of large commercial and industrial sector DSM programs. (1994-1996)

For a New England utility, worked on the project team developing a set of DSM evaluation master plans for incentive-type and third-party-contracting type DSM programs (1994)

For EPRI, wrote an overview of the status of DSM information systems and the potential effects of an increasingly competitive utility environment. (1993)

For two separate large New England utilities, helped to develop competitive procurement documents (DSM RFPs) for filing before the Massachusetts Department of Public Utilities. (1993, 1994)

For a midwestern utility, conducted a trade ally study designed to determine the influence of trade allies on the market for energy efficient lighting and motor equipment. (1992-1993)

DSM Implementation

Conducted detailed site visits and suggested efficiency improvement strategies for over 1,000 commercial, industrial and institutional buildings in Rhode Island. Performed end-use energy analysis and coordinated implementation of improvements. Worked with local utility DSM program personnel to educate building owners on DSM program opportunities. (1987-1992)

Energy Modeling

For Pollution Probe, development of simplified congestion (locked-in energy) model to estimate congestion quantity effects of an alternative to a proposed new 500 kV transmission line. (2008)

For various clientele, worked closely with the TCA GE MAPS modeling group on various facets of security-constrained dispatch modeling of electric power systems across the US and Canada. Specific tasks included assisting in designing MAPS model run parameters (e.g., base case and alternative scenarios specification); proposing modeling designs to clients; supporting input data gathering; interpreting model results; and writing summary reports, memos & testimony describing the results. (2002-2004)

For a group of potential electricity supply investors in Ontario, modeled the impact of proposed generation plant phaseout trajectories on investment requirements for new supply in Ontario. (2004)

For the Independent Power Producer's Society of Ontario, conducted a retrospective quantitative analysis of the Ontario market energy and ancillary service prices during the 15 months of the new wholesale market to determine the extent of infra-marginal rents available that could have supported entry for new generation. (2003)

In support of proposals to the US Dept. of Defense for military housing privatization, performed DOE-2 model runs using an online tool; and created a spreadsheet modeling tool to analyze the efficiency and cost effectiveness of new and renovated residential construction for base housing. Performed life-cycle utility cost analysis and prepared energy plans specifying building shell, equipment and appliance efficiency measures at 15 separate Army, Navy, and Air Force installations around the nation. (2001-2003)

For the Independent Power Producer's Society of Ontario, conducted a rate impact analysis of Ontario Hydro Networks Company proposed transmission tariff. (1999-2000)

For the University of Maryland at Baltimore, conducted a life-cycle cost analysis of alternative proposals for district-type thermal energy provision, comparing existing steam delivery systems to new hot-water systems. (1998)

For the UMass Medical Center (Worcester), conducted an energy use and cost allocation analysis of a large hospital complex to assist in choosing among electric and thermal energy supply options. (2000)

For an independent power producer, developed a spreadsheet-based tool to assess the rate impact of a "clean coal" facility compared to alternative gas-fired supply options. (1996-1997)

For a private consulting firm, examined electric end-use and generation capacity information in seven industry energy models and reported the sensitivities of each model to varying levels of input aggregation. (1995)

For a private industrial firm in Virginia, developed a Monte-Carlo simulation-based spreadsheet model to solve a capital budgeting problem involving long-term choice of industrial boiler equipment. (1995)

For a New England utility, developed a spreadsheet model to help determine economic decision-making processes used by energy service companies when delivering third-party procured DSM. (1995)

Petroleum and Natural Gas Industry Analysis
For a private independent power producer, conducted an analysis of the rate impacts of the Warrior Run clean coal (fluidized bed combustion) power plant in Maryland under various assumptions of natural gas prices and environmental regulation scenarios. (1996-1997)

For a British consulting firm, researched the current status of natural gas restructuring efforts in the US and their impact on regional US power generation markets. (1996)

For a Canadian law firm representing Native Canadian interests, conducted a detailed analysis of natural gas netback pricing for Alberta gas into US Midwest and West Coast markets over a thirty-year period. (1995)

For a US natural gas pipeline consortium, performed an econometric analysis of the demand for natural gas in the state of Florida. (1992-1993)

PAPERS, PUBLICATIONS AND PRESENTATIONS

Interstate Transfer of a DSM Resource: New Mexico DSM as an Alternative to Power from Mohave Generating Station. Jointly authored with Tim Woolf, Bill Steinhurst and Bruce Biewald. Presented at the 2006 ACEEE Summer Study on Energy Efficiency in Buildings and published in the proceedings. (2006)

SMD and RTO West: Where are the Benefits for Alberta? Keynote Paper prepared for the 9th Annual Conference of the Independent Power Producers Society of Alberta, with Dr. Richard D. Tabors, March 7, 2003.

A Progressive Transmission Tariff Regime: The Impact of Net Billing, presentation at the Independent Power Producer Society of Ontario annual conference, November 1999.

Tariff Structure for an Independent Transmission Company, with Richard D. Tabors, Assef Zobian, Narasimha Rao, and Rick Hornby, TCA Working Paper 101-1099-0241, November 1999.

Transmission Congestion Pricing Within and Around Ontario, presentation at the Canadian Transmission Restructuring Infocast Conference, Toronto, June 2-4, 1999.

The Restructured Ontario Electricity Generation Market and Stranded Costs. An internal company report presented to the Ontario Ministry of Energy and Environment on behalf of Enron Capital and Trade Resources Canada Corp., February 1998.

Alberta Legislated Hedges Briefing Note. An internal company report presented to the Alberta Department of Energy on behalf of Enron Capital and Trade Resources Canada, January 1998.

Generation Market Power in New England: Overall and on the Margin. Presentation at Infocast Conference: New Developments in Northeast and Mid-Atlantic Wholesale Power Markets, Boston, June 1997.

The Market for Power in New England: The Competitive Implications of Restructuring. Prepared for the Office of the Attorney General, Commonwealth of Massachusetts, by Tabors Caramanis & Associates with Charles River Associates, April 1996. R. Fagan was a key member of the team that produced the report.

Estimating DSM Impacts for Large Commercial and Industrial Electricity Users. Lead investigator and author, with M. Gokhale, D.S. Levy, P.J. Spinney, G.C. Watkins. Presented at The Seventh International Energy Program Evaluation Conference, Chicago, Illinois, August 1995, and published in the Conference Proceedings.

Sampling Issues in Estimating DSM Savings: An Issue Paper for Commonwealth Electric. Prepared with G.C. Watkins, Charles River Associates. Report for COM/Electric System, filed with the MA Dept. of Public Utilities (MDPU), April 28, 1995, Docket # DPU 95-2/3-CC-l.

Demand-side Management Information Systems (DSMIS) Overview. Electric Power Research Institute Technical Report TR-104707. Robert M. Fagan and Peter S. Spinney, principal investigators, prepared by Charles River Associates for EPRI, January 1995.

Impact Evaluation of Commonwealth Electric's Customized Rebate Program. With P.J. Spinney and G.C. Watkins. Charles River Associates, Initial and Updated Reports, April 1994, April 1995, and April 1996.1995 updated report filed with the MDPU, April28, 1995, Docket # DPU 95-2/3-CC-I. The initial report filed with the MDPU, April 1, 1994.

Northeast Utilities Energy Conscious Construction Program (Comprehensive Area): Level I and Level II Impact Evaluation Reports. With Peter S. Spinney (CRA) and Abbe Bjorklund (Energy Investments). Charles River Associates Reports prepared for Northeast Utilities, June and July 1994.

The Role of Trade Allies in C&I DSM Programs: A New Focus for Program Evaluation, Paper authored by Peter J. Spinney (Charles River Associates) and John Peloza (Wisconsin Electric Power Corp.). Presented by Bob Fagan at the Sixth International Energy Evaluation Conference, Chicago, Illinois, August 1993.

Resume dated June 2009.

Exhibit RMF-2

2012/2013 RPM Base Residual Auction Results

Executive Summary

The 2012/13 Reliability Pricing Model (RPM) Base Residual Auction (BRA) cleared 136,143.5MW of unforced capacity in the RTO at a Resource Clearing Price of $16.46/MW-day. This MW and price quantity pair on the RTO Variable Resource Requirement curve represents a 21.2% reserve margin; however when the Fixed Resource Requirement (FRR) load is considered the actual reserve margin for the entire RTO is 20.9%.

A total of 10,463.9 MW of incrementally new capacity in PJM was available for the 2012/2013 Base Residual Auction. This incrementally new capacity includes new generation capacity resources, capacity upgrades to existing generation capacity resources, new Demand Resources, upgrades to existing Demand Resources, and new Energy Efficiency Resources. The increase is partially offset by generation capacity derations to existing generation capacity resources to yield a net increase of over 7,210 MW of installed capacity. The 7,210 MW net increase in capacity represents nearly twice the increase in net capacity growth as compared to the 2011/2012 Delivery Year and is the largest single year increase in available capacity since the implementation of RPM.

The total quantity of Demand Resources offered into the 2012/2013 BRA was 9,847.6 MW (UCAP) which represents an increase of 496% over the Demand Resources that offered into the 2011/2012 BRA. Approximately 72% (7,047.3 MW) of these Demand Resources cleared in the auction. This significant increase was driven by the forward capacity market incentives and the elimination of the ILR alternative.

Starting with the BRA for the 2012/2013 Delivery Year, a new type of resource, Energy Efficiency Resource was permitted to offer as capacity supply. An Energy Efficiency (EE) Resource is a project that achieves a permanent, continuous reduction in electric energy consumption that is not reflected in the peak load forecast used for the Base Residual Auction for the Delivery Year. The amount of EE Resources offered in the auction was 652.7 MW (UCAP), or which 568.9 MW (87%) cleared.

MAAC, EMAAC, SWMAAC, PSEG, PSEG-North, and DPL-South were modeled as Locational Deliverability Areas (LDAs) in the 2012/13 RPM Base Residual Auction; however, only MAAC, EMAAC, PSEG-North, and DPL-South LDAs were binding constraints that resulted in Locational Price Adders. The Resource Clearing Prices for resources cleared in MAAC, EMAAC, PSEG-North, and DPL-South were $133.37/ MW-day, $139.73/MW-day, $185.00/MW-day, and $222.30/MW-day, respectively.

The RTO as a whole and each modeled LDA, with the exception of all suppliers in EMAAC not in the PS-NORTH or DPL-SOUTH LDAs, failed the Market Structure Test resulting in mitigation of any existing resources that failed the test in the execution of the RPM auction clearing. Cost-based offers or default avoidable cost rate values were utilized in the RPM auction clearing for all existing resources that failed the test.

2012/2013 RPM Base Residual Auction Results

The $16.46/MW-day RTO resource clearing price represents a decrease of $93.54/MW-day from the 2011/2012 BRA. The RPM auction price was lower because of a growth in the available capacity and a decline in demand. Supply increased because of the significant increases in new capacity from demand resources and energy efficiency resources. Demand declined due to a 446 MW decrease in the RTO preliminary peak load forecast from 145,303 MW (adjusted to include the load in Duquesne zone) in 2011/12 Delivery Year to 144,857 MW in the 2012/13 Delivery Year.

A further discussion of the 2012/2013 Base Residual Auction results are detailed in the body of this report.

2012/2013 RPM Base Residual Auction Results

Introduction

This document provides additional information regarding the 2012/13 Reliability Pricing Model (RPM) Base Residual Auction results. The discussion also provides a comparison of the 2012/2013 auction results to the results from the 2007/2008 through 2011/2012 RPM auctions.

Significant Changes to RPM Design since the 2011/2012 Base Residual Auction

The FERC Order on RPM dated March 26, 2009 and the Clarification Response dated May 1, 2009 included the acceptance of several significant changes to the design of the Reliability Pricing Model that impacted either the Demand or Supply curves for the 2012/2013 Base Residual Auction. Highlights of the changes are included below, and additional details are located in the FERC documents, the PJM Tariff, and the PJM Capacity Market Manual (M-18), all available on the pjm.com website.

Changes that impacted the Demand Curve:

- Load in the Duquesne Zone was included in the RTO demand curve for 2012/2013, but was not included in the 2011/2012 RTO demand curve.
- The Cost of New Entry values that serve as the basis for price on the RTO and LDA demand curves increased by 56% (for the RTO) over the 2011/2012 values.
- The ILR Forecast was replaced with a Short Term Resource Procurement value. As a result, 2.5% of the Reliability Requirement (3,343.3 MW) was removed from the demand curve for procurement in later auctions for 2012/2013.
- The criteria for modeling of Locational Deliverability Areas starting with the 2012/13 Delivery Year includes a CETL to CETO threshold ratio of 115% rather than 105%, as well as a mandate to model the EMAAC, SWMAAC, and MAAC regions and any other LDA that had a locational price adder in the last three immediately preceding Base Residual Auctions.

Changes that impacted the Supply Curve:

- The Interruptible Load for Reliability product was discontinued as of 2012/2013, causing several thousand MW of interruptible load to offer into the auction as Demand Response resources.

2012/2013 RPM Base Residual Auction Results

- Two new types of resources, Energy Efficiency and Planned External Generation, were permitted to offer in as supply resources in 2012/2013.
- Generation sell offer changes included the removal of the EFORd Risk Segment (which could be offered at Net CONE) and a change to the maximum sell offer EFORd that was used to convert the Installed Capacity offered into the auction into the Unforced Capacity cleared in the auction.
- Existing Generation Resources that planned to make large capital expenditures for the Delivery Year were permitted to elect the New Entry Pricing Adjustment option.
- The Avoidable Cost Rate (ACR) default values were increased to adjust historical ACR data to the appropriate level for the 2012/13 Delivery Year. The default ACR values are the default offer caps that suppliers may elect to use in the event the Market Structure Test is failed and the supplier chooses not to calculate a unit-specific ACR data.

2012/2013 RPM Base Residual Auction Results

2012/2013 Base Residual Auction Results Discussion

Table 1 contains a summary of the RTO clearing prices resulting from the 2012/2013 RPM Base Residual Auction in comparison to those from 2007/2008 through 2011/2012 RPM Base Residual Auctions.

Table 1 –RPM Base Residual Auction Resource Clearing Price Results in the RTO

	RTO					
Auction Results	**2007/2008**	**2008/2009**	**2009/2010**	**2010/2011**	**2011/2012**	**2012/2013**
Resource Clearing Prices	$40.80	$111.92	$102.04	$174.29	$110.00	$16.46
Cleared UCAP (MW)	129,409.2	129,597.6	132,231.8	132,190.4	132,221.5	136,143.5
Reserve Margin	19.2%	17.5%	17.8%	16.5%	18.1%	20.9%

*2011/2012 BRA was conducted without Duquesne zone load.

The Resource Clearing Price is the marginal clearing price that will be paid to each cleared Capacity Resource in dollars per MW-day. The cleared UCAP is the amount of unforced capacity that was procured in the auction to meet the RTO demand for capacity. These two quantities represent the point on the Variable Resource Requirement curve where the RTO cleared for each particular auction. For the 2012/13 Delivery Year, the point of the Variable Resource Requirement curve where the RTO cleared represents a 21.2% reserve margin; however, when the Fixed Resource Requirement (FRR) load is considered the actual resource margin for the entire RTO is 20.9%. The Reserve Margin presented in Table 1 represents the percentage of installed capacity cleared in excess the RTO load (including load served under the Fixed Resource Requirement alternative).

The 2012/2013 Base Residual Auction results reflect very strong participation by Demand Resources, meaningful participation from Energy Efficiency Resources, and growing development of renewable resources.

Demand Resource Participation

The total quantity of Demand Resources offered into the 2012/2013 BRA represented an increase of 496% over the Demand Resources that offered into the 2011/2012 BRA. Of the 9,874 MW of total demand response that offered in this auction, 7,047.3 MW cleared and will be awarded capacity payments. Of this cleared amount, 4,723.8 MW (67%) was located in the constrained regions, illustrating investment in demand response in higher price regions where such response is needed.

One reason for the increase in Demand Resource participation in the 2012/2013 Base Residual Auction was the elimination of the Interruptible Load for Reliability (ILR) product beginning with the 2012/2013 Delivery Year. The ILR product allowed for sites with load reduction capability to make the commitment to be a capacity resource several months ahead of the Delivery Year rather than making that commitment by clearing in a Base Residual or Incremental Auction. With the elimination of this option, several thousand MW of load management sites were offered into the 2012/2013 BRA as "existing" Demand Resources. The forward capacity market also provides incentive for demand response investment as indicated by the addition of several thousand MW of load management sites that were offered as Planned Demand Resources. Per the market mitigation rules, existing DR is offer capped at a sell offer price equal to $0/MW-day, making these resources price-takers for the 2012/2013 Delivery Year. Planned Demand Resources were required to meet the RPM credit requirements imposed on all new resources, and were not subject to offer caps.

Table 3A contains a comparison of the DR and EE that was offered and cleared in the 2011/2012 and 2012/2013 BRA on a zonal basis.

Table 3A – Comparison of Demand Resources and Energy Efficiency Resources Offered versus Cleared in the 2012/13 BRA represented in UCAP

	Offered MW*			Cleared MW*		
Zone	Demand	EE	Total	Demand	EE	Total
AECO	78.9	1.9	**80.8**	75.1	1.2	**76.3**
AEP	1352.7	2.6	**1355.3**	710.8	0	**710.8**
APS	582.4	0	**582.4**	272.9	0	**272.9**
BGE	1370.6	105.8	**1476.4**	1312.9	103.2	**1416.1**
COMED	1049	386.4	**1435.4**	658	386.4	**1044.4**
DAY	405.6	0	**405.6**	112.3	0	**112.3**
DOM	1237.9	76.6	**1314.5**	494.7	2.4	**497.1**
DPL	289.6	12.7	**302.3**	283	12.2	**295.2**
DUQ	190.8	0.2	**191**	74.8	0.2	**75**
JCPL	362.7	2.8	**365.5**	321.9	1.8	**323.7**
METED	267.2	0	**267.2**	252	0	**252**
PECO	581.2	2.9	**584.1**	496.4	1.9	**498.3**
PENELEC	286.1	0.2	**286.3**	276.3	0.2	**276.5**
PEPCO	485.1	56.5	**541.6**	460.8	56.5	**517.3**
PPL	832.9	0	**832.9**	783.3	0	**783.3**
PSEG	472.9	4.1	**477**	460.1	2.9	**463**
RECO	2	0	**2**	2	0	**2**
Total	**9847.6**	**652.7**	**10500.3**	**7047.3**	**568.9**	**7616.2**

*All MW Values are in UCAP Terms

Energy Efficiency Resource Participation

Starting with the BRA for the 2012/2013 Delivery Year, Energy Efficiency Resources were permitted to offer as capacity supply resources. An Energy Efficiency (EE) Resource is a project that involves the installation of more efficient devices/equipment or the implementation of more efficient processes/systems exceeding then-current building codes, appliance standards, or other relevant standards at the time of installation as known at the time of commitment. The EE Resource must achieve a permanent, continuous reduction in electric energy consumption (during the defined EE performance hours) that is not reflected in the peak load forecast used for the Base Residual Auction for the Delivery Year for which the EE Resource is proposed. The EE Resource must be fully implemented at all times during the delivery year, without any requirement of notice, dispatch, or operator intervention. Of the 652.7 MWs of Energy Efficiency that offered into the 2012/2013 Base Residual Auction, 568.9 MW of EE Resources cleared in the auction and will be awarded capacity payments.

Table 3B contains a summary of the demand resources and energy efficiency resources that offered and cleared by zone in the 2012/2013 Base Residual Auction. Approximately 72% of the Demand Resources and 87% of the Energy Efficiency Resources that were offered into the BRA cleared. The uncleared resources were offered at a price above the clearing price for the LDA in which the resource was offered.

Table 3B – Comparison of Demand Resources Offered and Cleared in 2011/12 BRA & 2012/13 BRA represented in UCAP

	Offered MW*			Cleared MW*		
Zone	2011/2012	2012/2013	Increase in Offered MW	2011/2012	2012/2013	Increase in Cleared MW
AECO	11.7	78.9	67.2	7	75.1	68.1
AEP	24.2	1352.7	1328.5	14.6	710.8	696.2
APS	88.6	582.4	493.8	57.3	272.9	215.6
BGE	628.3	1370.6	742.3	595.8	1312.9	717.1
COMED	158	1049	891	127.3	658	530.7
DAY	25.4	405.6	380.2	15.3	112.3	97
DOM	155.8	1237.9	1082.1	105.9	494.7	388.8
DPL	58.9	289.6	230.7	43.8	283	239.2
DUQ	0	190.8	190.8	0	74.8	74.8
JCPL	55.4	362.7	307.3	46.4	321.9	275.5
METED	23.8	267.2	243.4	14.3	252	237.7
PECO	131.3	581.2	449.9	103.2	496.4	393.2
PENELEC	27.1	286.1	259	16.2	276.3	260.1
PEPCO	150.9	485.1	334.2	144.8	460.8	316
PPL	63.4	832.9	769.5	42.2	783.3	741.1
PSEG	49.6	472.9	423.3	30.8	460.1	429.3
RECO	0	2	2	0	2	2
Total	**1652.4**	**9847.6**	**8195.2**	**1364.9**	**7047.3**	**5682.4**

*All MW Values are in UCAP Terms

Figure 2 illustrates the demand side participation in the PJM Capacity Market from 2005/2006 Delivery Year to the 2012/2013 Delivery Year. Demand side participation includes active load management (ALM) prior to 2007/2008 Delivery Year, Interruptible Load for Reliability (ILR) and Demand Resources starting with 2007/2008 Delivery Year, and Energy Efficiency Resources starting with the 2012/2013 Delivery Year. The demand side participation in the capacity market has increased dramatically since the inception of RPM in the 2007/2008 Delivery Year.

Figure 2 – Demand Side Participation in the PJM Capacity Market

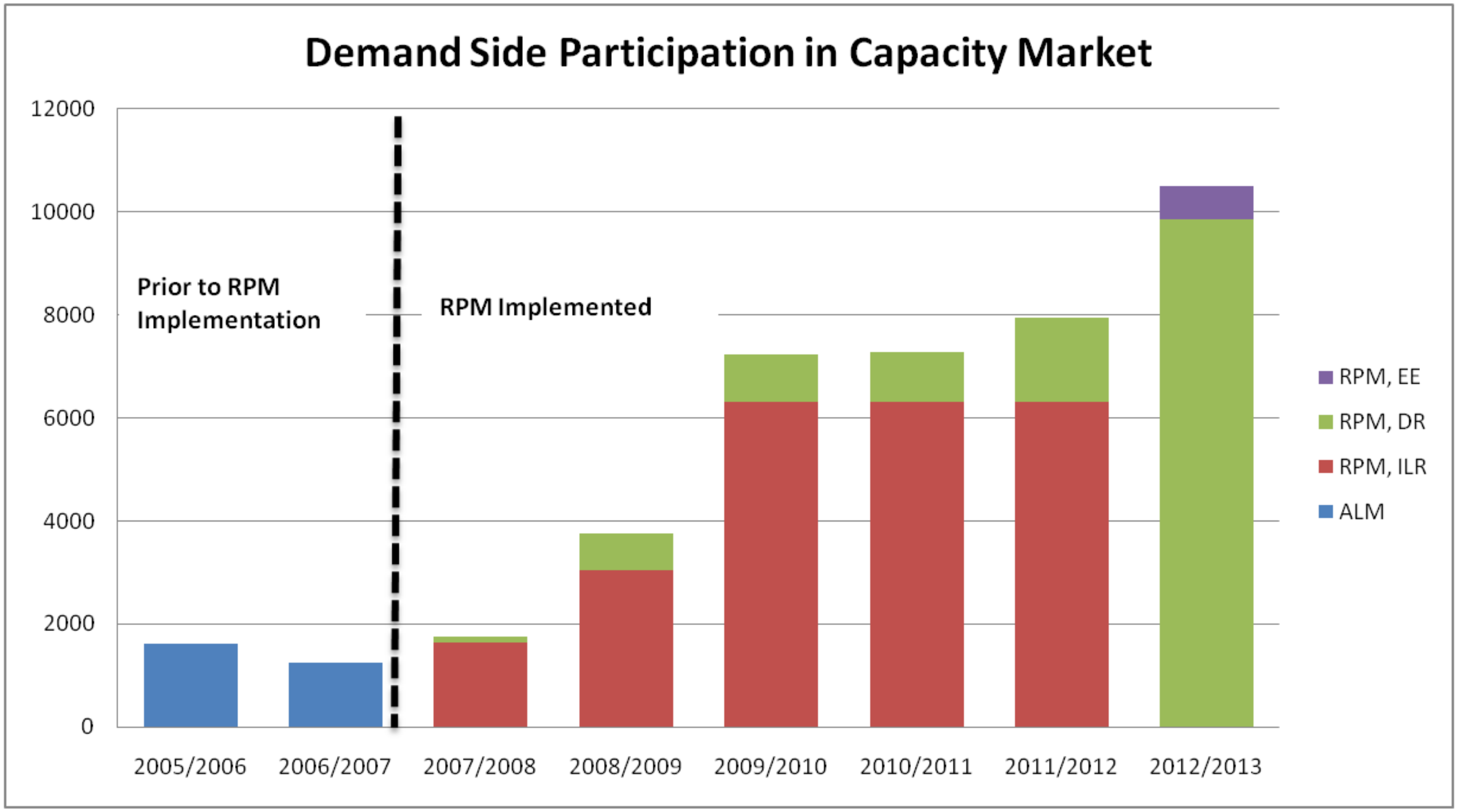


*Figure 2 represents in UCAP terms the DR and EE offered into the Base Residual Auction, actual ILR that was certified for 2007/2008 – 2009/2010 Delivery Years and estimated ILR for 2010/2011 and 2011/2012 Delivery Years (based on the 2009/2010 actual certification values).

2012/2013 RPM Base Residual Auction Results

Renewable Resource Participation

340.4 MW of wind resources were offered into the 2012/2013 Base Residual Auction. Of those, 323.4 MW of wind resources cleared in the auction. The capacity factor applied to wind resources is 13%, meaning that for every 100 MW of wind energy, 13 MW are eligible to meet capacity requirements. The 323.4 MW of cleared wind capacity translates to 2,488 MW of wind energy that is expected to be available in the 2012/2013 Delivery Year.

LDA Results

For the 2012/13 Base Residual Auction, the criteria to establish separate VRR curves for LDAs were expanded to ensure that LDAs that might result in price separation would be modeled in the auction. An LDA was modeled in the Base Residual Auction and has a separate VRR Curve if (1) the LDA has a CETO/CETL margin that is less than 115%; or (2) the LDA had a locational price adder in any of the three immediately preceding Base Residual Auctions; or (3) the LDA is likely to have a locational price adder based on a PJM analysis using historic offer price levels; or (4) the LDA is EMAAC, SWMAAC, and MAAC.

As a result of the expanded criteria, MAAC, EMAAC, SWMAAC, PSEG, PSEG-North, and DPL-South were modeled as constrained Locational Deliverability Areas (LDAs) in the 2012/13 RPM Base Residual Auction; however, only MAAC, EMAAC, PSEG-North, and DPL-South LDAs were binding constraints that resulted in Locational Price Adders. A Locational Price Adder represents the difference in Resource Clearing Prices between a resource in a constrained LDA and the immediate higher level LDA.

Table 1A contains a summary of the clearing results in the LDAs from the 2012/2013 RPM Base Residual Auction.

Table 1A –RPM Base Residual Auction Clearing Results in the LDAs

Auction Results	RTO	MAAC	EMAAC	SWMAAC	PSEG	PS-NORTH	DPL-SOUTH
Offered MW (UCAP)	145,373.3	68,282.5	32,982.5	12,395.8	7,431.4	3,419.6	1,498.9
Cleared MW (UCAP)	136,143.5	65,452.3	31,080.2	11,594.5	7,194.0	3,521.9	1,241.5
Resource Clearing Price	$ 16.46	$ 133.37	$ 139.73	$ 133.37	$ 139.73	$ 185.00	$ 222.30
Locational Price Adder*	$ -	$ 116.91	$ 6.36	$ -	$ -	$ 45.27	$ 82.57

*Locational Price adder is with respect to the immediate parent LDA

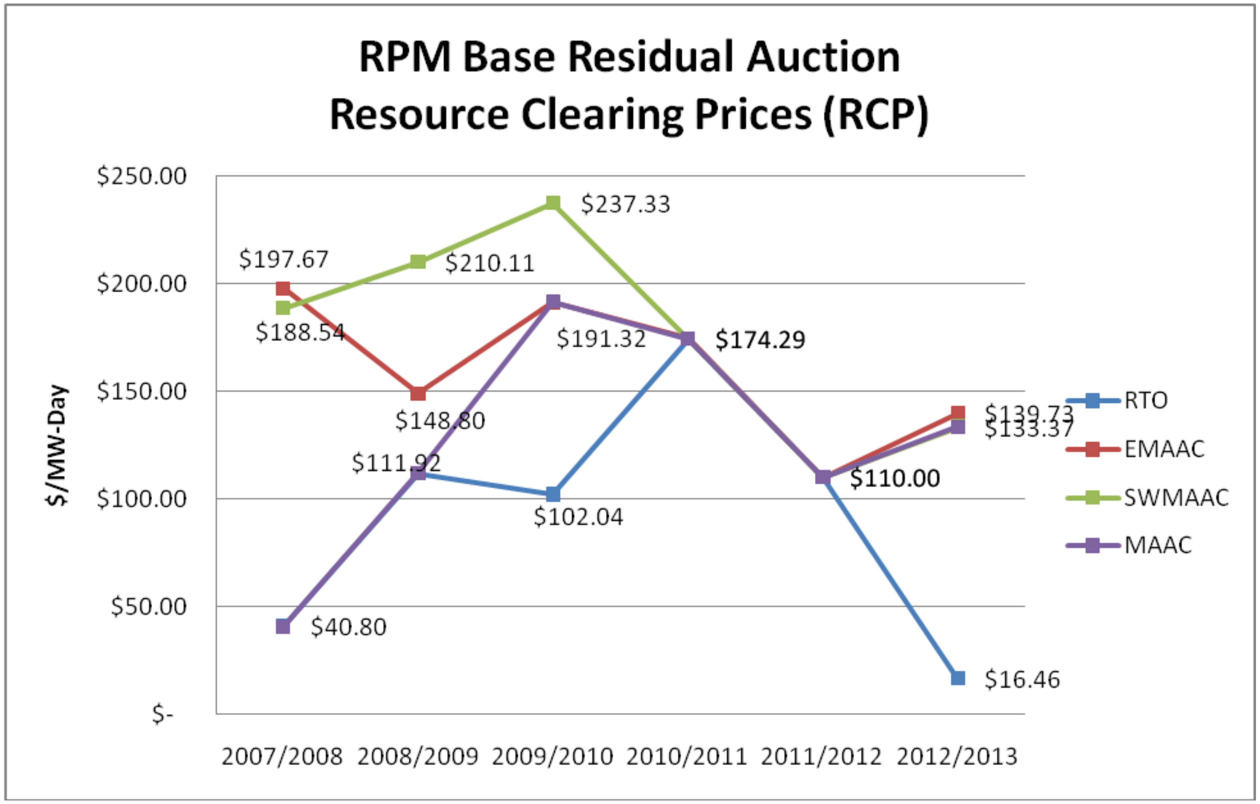
Since MAAC, EMAAC, PSEG-North, and DPL-South were constrained LDAs that are importing capacity, Capacity Transfer Rights (CTRs) will be allocated to loads in those constrained LDAs for the 12/13 Delivery Year. CTRs are allocated by load ratio share to all

Load Serving Entities (LSEs) in a constrained LDA that has a higher clearing price than the unconstrained region. CTRs serve as a credit back to the LSEs in the constrained LDA for use of the transmission system to import less expensive capacity into that constrained LDA and are valued at the difference in the clearing prices of the constrained and unconstrained regions.

Mitigation – The RTO as a whole and each modeled LDA, with the exception of all suppliers in EMAAC not in the PS-NORTH or DPL-SOUTH LDAs, failed the Market Structure Test resulting in mitigation of any existing resources that failed the test in the execution of the RPM auction clearing. Cost-based offers or default avoidable cost rate values were utilized in the RPM auction clearing for all existing resources.

Figure 1 illustrates the trends in Resource Clearing Prices for each RPM Base Residual Auction cleared to date.

Figure 1 – Base Residual Auction Resource Clearing Prices



* RTO and MAAC Resource Clearing Prices for the 2007/2008, 2008/2009, 2010/2011, and 2011/2012 BRA are equal.
**EMMAC and MAAC Resource Clearing Prices for the 2009/2010, and 2010/2011, and 2011/2012 BRA are equal.
**SWMAAC and MAAC Resource Clearing Prices for the 2010/2011, 2011/2012, and 2012/13 BRA are equal.

Table 2 contains a summary of the offer and resultant data in the RTO for each cleared Base Residual Auction from 2008/09 through the 2012/2013 Delivery Years. The summary includes all resources located in the RTO (including all LDAs within the RTO) and notes the capacity located outside the PJM footprint that was offered into the auction.

Table 2 –RPM Base Residual Auction Generation, Demand, and Energy Efficiency Resource Information in the RTO

2012/2013 RPM Base Residual Auction Results

	RTO*				
Auction Supply (all values in ICAP)	**2008/2009**	**2009/2010**	**2010/2011**	**2011/2012****	**2012/2013**
Internal PJM Capacity	166,037.9	167,026.3	168,457.3	169,241.6	179,791.2
Imports Offered	2,612.0	2,563.2	2,982.4	6,814.2	4,152.4
Total Eligible RPM Capacity	**168,649.9**	**169,589.5**	**171,439.7**	**176,055.8**	**183,943.6**
Exports / Delistings	4,205.8	2,240.9	3,378.2	3,389.2	2,783.9
FRR Commitments	24,953.5	25,316.2	26,305.7	25,921.2	26,302.1
Excused	722.0	1,121.9	1,290.7	1,580.0	1,732.2
Total Eligible RPM Capacity - Excused	**29,881.3**	**28,679.0**	**30,974.6**	**30,890.4**	**30,818.2**
Remaining Eligible RPM Capacity	**138,768.6**	**140,910.5**	**140,465.1**	**145,165.4**	**153,125.4**
Generation Offered	138,076.7	140,003.6	139,529.5	143,568.1	142,957.7
DR Offered	691.9	906.9	935.6	1,597.3	9,535.4
EE Offered	0.0	0.0	0.0	0.0	632.3
Total Eligible RPM Capacity Offered	**138,768.6**	**140,910.5**	**140,465.1**	**145,165.4**	**153,125.4**
Total Eligible RPM Capacity Unoffered	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

*RTO numbers include all LDAs.

**All generation in the Duquesne zone is considered external to PJM for the 2011/2012 BRA.

A total of 183,943.6 MW of installed capacity was eligible to be offered into the 2012/2013 Base Residual Auction. Of this eligible amount, 4,152.4 MW were from external resources that had fulfilled the eligibility requirements to be considered a PJM Capacity Resource. A portion of the external resource total was included in FRR Capacity Plans, and the remainder was offered into the auction. As illustrated in *Table 2*, the amount of capacity exports decreased in the 2012/2013 auction compared to the previous auction. FRR commitments increased by 380.9 MW from the 2011/2012 Delivery Year due an increase in FRR capacity obligations.

A total of 153,125.4 MW of installed capacity was offered into the Base Residual Auction. This is an increase of almost 8000 MW over what was offered into the 2011/2012 BRA. A total of 30,818.2 MW was eligible, but was not offered due to 1) inclusion in an FRR Capacity Plan, 2) export of the resource, or 3) having been excused from offering into the auction. Resources were excused from the must offer requirement for the following reasons: environmental restrictions, approved retirement requests not yet reflected in eRPM, and excess capacity owned by an FRR entity.

Participants' sell offer EFORd values were used to translate the generation installed capacity values into unforced capacity (UCAP) values. Demand Resource (DR) sell offers and Energy Efficiency Resource (EE) sell offers were converted into UCAP using the appropriate Demand Resource (DR) Factor and Forecast Pool Requirement (FPR) for the delivery year. In UCAP, a total of 145,373.3 MW were offered into the 2012/2013 Base Residual Action, comprised of 134,873 MW of generation capacity, 9,847.6 MW of capacity from Demand Resources, and 652.7 MW of capacity from Energy Efficiency Resources. Of those offered, a total of 136,143.5 MW of capacity was cleared in the auction.

Of the 136,143.5 MW of capacity that cleared in the auction, 128,527.4 MW were from generation capacity, 7,047.3 MW were from Demand Resources, and 568.9 MW were from Energy Efficiency Resources. Capacity that was offered but not cleared in the Base Residual Auction will be eligible to offer into the First, Second and Third Incremental Auctions for the 2012/2013 Delivery Year. *Table 3* illustrates the Generation, Demand Resources, and Energy Efficiency Resources Offered and Cleared in the RTO translated into Unforced Capacity MW amounts.

Table 3 – Generation, Demand Resources, and Energy Efficiency Resources Offered and Cleared Represented in Unforced Capacity MW

	RTO*				
Auction Results (all values in UCAP)**	**2008/2009**	**2009/2010**	**2010/2011**	**2011/2012**	**2012/2013**
Generation Offered	131,164.8	132,614.2	132,124.8	136,067.9	134,873.0
DR Offered	715.8	936.8	967.9	1,652.4	9,847.6
EE Offered	-	-	-	-	652.7
Total Offered	**131,880.6**	**133,551.0**	**133,092.7**	**137,720.3**	**145,373.3**
Generation Cleared	129,061.4	131,338.9	131,251.5	130,856.6	128,527.4
DR Cleared	536.2	892.9	939.0	1,364.9	7,047.3
EE Cleared	0.0	0.0	0.0	0.0	568.9
Total Cleared	**129,597.6**	**132,231.8**	**132,190.5**	**132,221.5**	**136,143.6**
Uncleared	2,283.0	1,319.2	902.2	5,498.8	9,229.7

* RTO numbers include all LDAs

** UCAP calculated using sell offer EFORd for Generation Resources. DR and EE UCAP values include appropriate FPR and DR Factor.

Table 4 contains a summary of capacity additions and reductions from the 2011/2012 Base Residual Auction to the 2012/2013 Base Residual Auction. A total of 10,463.9 MW of incrementally new capacity in PJM was available for the 2012/2013 Base Residual Auction. This incrementally new capacity includes new generation capacity resources, capacity upgrades to existing generation capacity resources, new Demand Resources, upgrades to existing Demand Resources, and new Energy Efficiency Resources. The increase is partially offset by generation capacity derations to existing generation capacity resources to yield a net increase of 7,210 MW of installed capacity. The 7,210 MW net increase in capacity represents nearly double the increase in net capacity growth as compared to the 2011/2012 Delivery Year and is the largest single year increase in capacity since the implementation of RPM.

Table 4 also illustrates the total amount of resource additions and reductions over six Delivery Years since the implementation of the RPM construct. Over the period covering the first six RPM Base Residual Auctions, 9,844.5 MW of new generation capacity was added which was partially offset by 5,420.6 MW of capacity derations or retirements over the same period. Additionally, 9,973.2 MW of new Demand Resources were offered over these last six auctions, and 632.3 MW of new Energy Efficiency resources were offered in the 2012/2013 auction. The total net increase in installed capacity in PJM over the period of the last six RPM auctions was 15,029.4 MW.

Table 4 – Incremental Capacity Resource Additions and Reductions to Date

	RTO*						
Capacity Changes (in ICAP)	**2007/2008**	**2008/2009**	**2009/2010**	**2010/2011**	**2011/2012**	**2012/2013**	**Total**
Increase in Generation Capacity	602.0	724.2	1,272.3	1,776.2	3,576.3	1,893.5	9,844.5
Decrease in Generation Capacity	-674.6	-375.4	-550.2	-301.8	-264.7	-3,253.9	-5,420.6
Net Increase in Demand Resource Capacity**	555.0	574.7	215.0	28.7	661.7	7,938.1	9,973.2
Net Increase in Energy Efficiency Capacity**	0.0	0.0	0.0	0.0	0.0	632.3	632.3
Net Increase in Installed Capacity	**482.4**	**923.5**	**937.1**	**1,503.1**	**3,973.3**	**7,210.0**	**15,029.4**

* RTO numbers include all LDAs

** Values are with respect to the quantity offered in the previous year's Base Residual Auction.

^ Values include 2007/2008 values not posted in this report but available on PJM.com.

Table 4A provides a further breakdown of the generation uprates and derates for the 2012/2013 Delivery Year on an LDA basis.

Table 4A – Generation Uprates and Derates by LDA effective 2012/2013 Delivery Year

LDA Name	Uprates	Derates
DPL-SOUTH	0.0	-34.8
EMAAC	131.5	-108.8
MAAC	164.7	-56.8
PSEG	387.5	-223.6
PS-NORTH	2.7	-814.8
RTO	1169.1	-1172.1
SWMAAC	38.0	-843.0
Total	1893.5	-3253.9

**All Values in ICAP terms

Table 5 provides a further breakdown of the new capacity offered into the each BRA into the categories of new resources, reactivated units, and uprates to existing capacity, and then further down into resource type. As shown in this table, there was a decrease in the amount of generating capacity from new resources offered into the 2012/2013 BRA in comparison with the 2011/12 BRA. The capacity offered in the 2012/2013 BRA from both new generating resources and uprates to existing resources include gas, diesel, coal, wind, and nuclear resources. While the largest growth remains in gas turbines and combined cycle plants, a fair amount of incremental capacity in Steam (coal) and Nuclear was offered into the recent auctions.

Figure 5A provides an illustration of the cumulative increase in new generation capacity by fuel type since the inception of RPM (June 1, 2007). A new combined cycle unit represents the largest increase by fuel type for 2012/2013. To date, coal units and incremental nuclear upgrades have provided diversity by clearing nearly 3,000 MW of base load capacity. Although less upgrades to existing generating capacity were observed in 2012/2013 Delivery Year than 2011/2012 Delivery Year, a fair amount of upgrades to existing generating capacity are occurring in 2012/2013 Delivery Year which shows that capacity revenues that are going to existing generators are being reinvested to maintain and enhance those units.

Table 5 – Further Breakdown of Incremental Capacity Resource Additions from 2007/2008 to 2012/13

	Delivery Year	CT/GT	Combined Cycle	Diesel	Hydro	Steam	Nuclear	Solar	Wind	Total
New Capacity Units (ICAP MW)	2007/2008			18.7	0.3					19.0
	2008/2009			27.0					66.1	93.1
	2009/2010	399.5		23.8		53.0				476.3
	2010/2011	283.3	580.0	23.0					141.4	1027.7
	2011/2012	416.4	1135.0			704.8		1.1	75.2	2332.5
	2012/2013	403.8	585.0	7.8		36.3			75.1	1108.0
Capacity from Reactivated Units (ICAP MW)	2007/2008					47.0				47.0
	2008/2009					131.0				131.0
	2009/2010									0.0
	2010/2011	160.0		10.7						170.7
	2011/2012	80.0				101.0				181.0
	2012/2013									0.0
Uprates to Existing Capacity Resources (ICAP MW)	2007/2008	114.5		13.9	80.0	235.6	92.0			536.0
	2008/2009	108.2	34.0	18.0	105.5	196.0	38.4			500.1
	2009/2010	152.2	206.0		162.5	61.4	197.4		16.5	796.0
	2010/2011	117.3	163.0		48.0	89.2	160.3			577.8
	2011/2012	369.2	148.6	57.4		186.8	292.1		8.7	1062.8
	2012/2013	231.2	164.3	14.2		193.0	126.0		56.8	785.5
	Total	2835.6	3015.9	214.5	396.3	2035.1	906.2	1.1	439.8	9844.5

Figure 5A represents the cumulative increase in new generation capacity by fuel type since the inception of RPM (June 1, 2007).

Figure 5A: Cumulative Generation Capacity Increases by Fuel Type

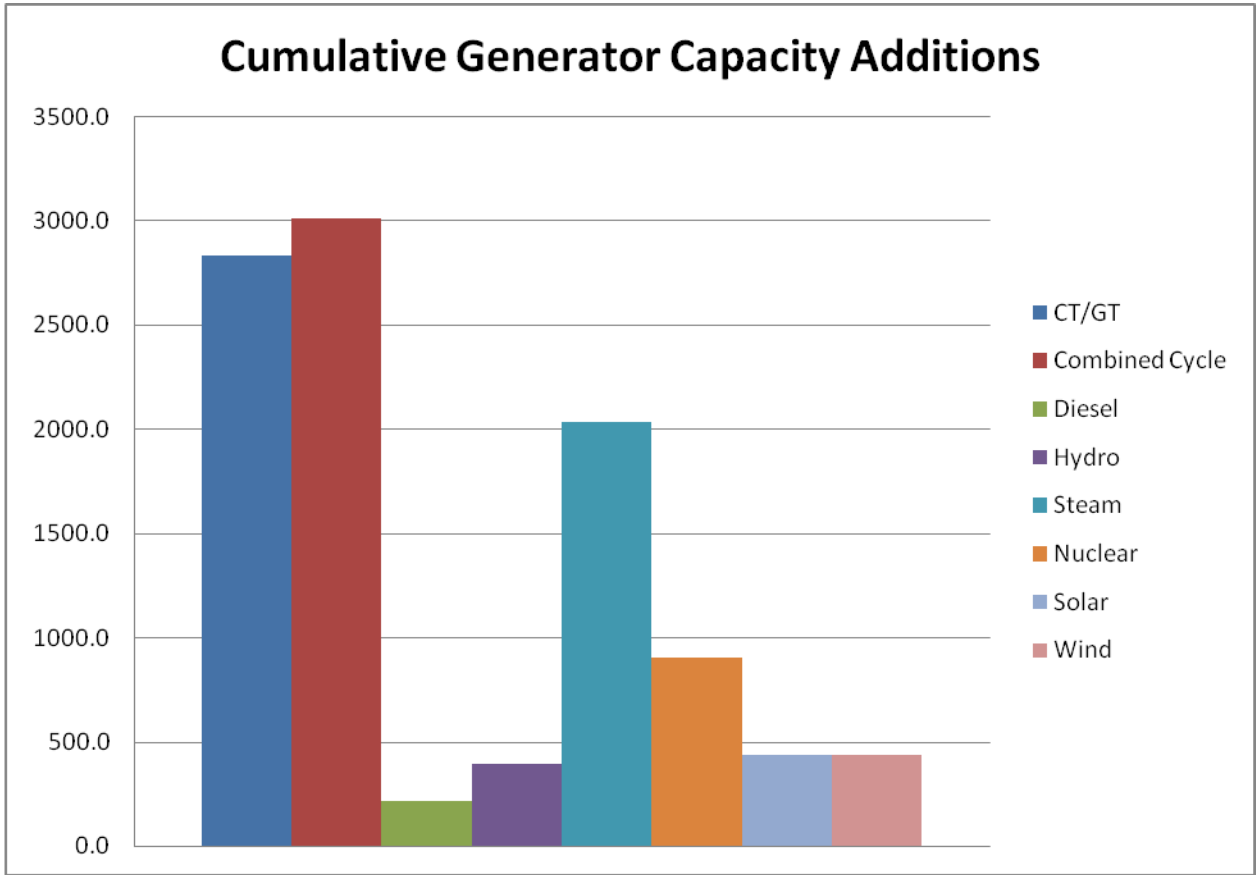


Table 6 shows the changes that have occurred regarding resource deactivation and retirement since the RPM was approved by FERC. The MW values illustrated in *Table 6* represent the quantity of unforced capacity cleared in 2012/2013 Base Residual Auction that came from resources that have either withdrawn their request to deactivate, postponed retirement, or been reactivated (i.e., came out of

retirement or mothball state for the RPM auctions) since the RPM Settlement. This total accounts for 3,276.8 MW of cleared UCAP in the 2012/2013 BRA which equates to 3,825.6 MW of ICAP Offered.

Table 6 – Changes to Generation Retirement Decisions Since RPM Approval

	RTO*	
Generation Resource Decision Changes	**ICAP Offered**	**UCAP Cleared**
Withdrawn Deactivation Requests	2121.1	1798.7
Postponed or Cancelled Retirement	1523.5	1302.9
Reactivation	181.0	175.2
Total	**3825.6**	**3276.8**

Values Represent Offered ICAP and Cleared UCAP in the 2012/2013 BRA

* RTO numbers include all LDAs

Note: Not all survey data has been returned by participants. Values represent latest totals.

RPM Impact To Date

As illustrated in *Table 2*, for the 2012/2013 auction, the capacity exports were 2,783.9 MW and the capacity imports were 4,152.4 MW. The difference between the capacity imports and exports results is a net capacity import of 1,368.5 MW.

In the planning year preceding the RPM auction implementation, 2006/2007, there was a net capacity export of 2,616.0 MW. In this auction, PJM is now a net importer of 1,368.5 MW. Therefore RPM's impact on PJM capacity interchange is 3,984.5 MW.

The minimum net impact of the RPM implementation on the availability of Installed Capacity resources for the 2012/2013 planning year can be estimated by adding the net change in capacity imports and exports over the period, the forward demand and energy efficiency resources, the increase in Installed Capacity over the RPM implementation period from *Tables 4* and the net change generation retirements from *Table 6*. Therefore, as illustrated in Table 7, the minimum estimated net impact of the RPM implementation on the availability of capacity in the 2012/2013 compared to what would have happened absent this implementation was 27,751.3 MW.

Table 7 shows the details on RPM's impact to date in ICAP terms.

Table 7 – RPM's Impact To Date

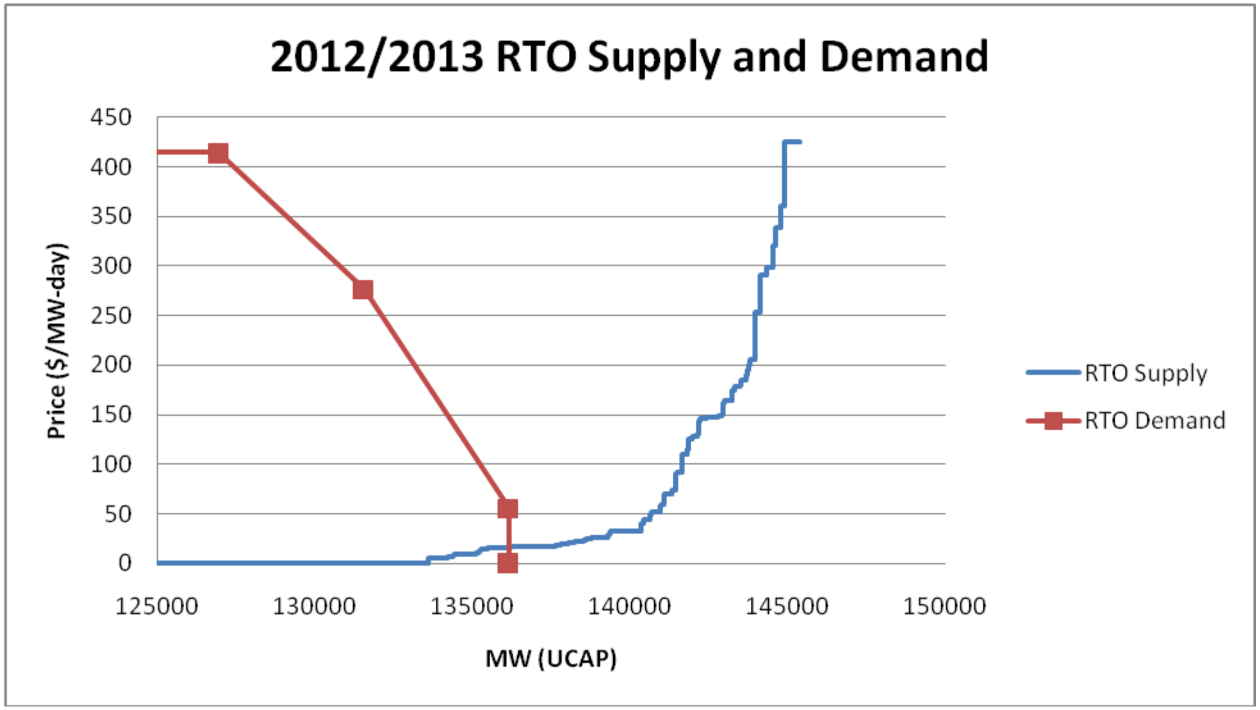
Change in Capacity Availability	Installed Capacity MW
New Generation	5056.6
Generation Upgrades (not including reactivations)	4258.2
Generation Reactivation	529.7
Forward Demand and Energy Efficiency Resources	10167.1
Cleared ICAP from Withdrawn or Canceled Retirements	3644.6
Net increase in Capacity Imports	3984.5
Total Impact on Capacity Availability in 2012/2013 Delivery Year	27640.7

Discussion of Factors Impacting the RPM Clearing Prices

RTO Clearing Price

The market clearing price of $16.46/ MW-Day in the RTO was set by the intersection of the Supply Curve with the Variable Resource Requirement (VRR) Curve on the vertical segment of the VRR Curve. This represents a decrease of $93.54/MW-day from the 2011/2012 Base Residual Auction where the RTO clearing price was $110.00/MW-day. The 136,143.5MW of UCAP cleared in the auction represents an increase in cleared UCAP of 3,922 MW over the 2011/2012 Base Residual Auction results and a reserve margin of over 20%. *Figure 1* graphically depicts the supply and demand curve intersection in the RTO.

Figure 1 – Graphical Illustration of RTO Clearing Results for 2012/2013 Base Residual Auction



The increase in cleared UCAP in the RTO and the decrease in the clearing price were a result of the new capacity introduced in this auction and also a large decrease in the amount of exports leaving the PJM system. Combined, these account for over 2,650 MW that were offered into the 2012/2013 Base Residual Auction that were not offered into the 2011/2012. This growth in available capacity exceeds the demand growth in the RTO, modeled in the VRR curve, and thus causes a decrease in the RTO clearing price and a higher reserve margin.

The unmitigated supply curve for the RTO is depicted in *Figure 2*. The plot represents the UCAP offered by all participants at the EFORd and price submitted with that offer. *Figure 3* shows the mitigated supply curve for the RTO. The mitigated supply curve was used to clear the 2012/13 Base Residual Auction, as all market participants failed the Market Structure Test for the RTO and were subject to offer capping for existing resources.

Figure 2 - Supply Curve for the RTO (Unmitigated)

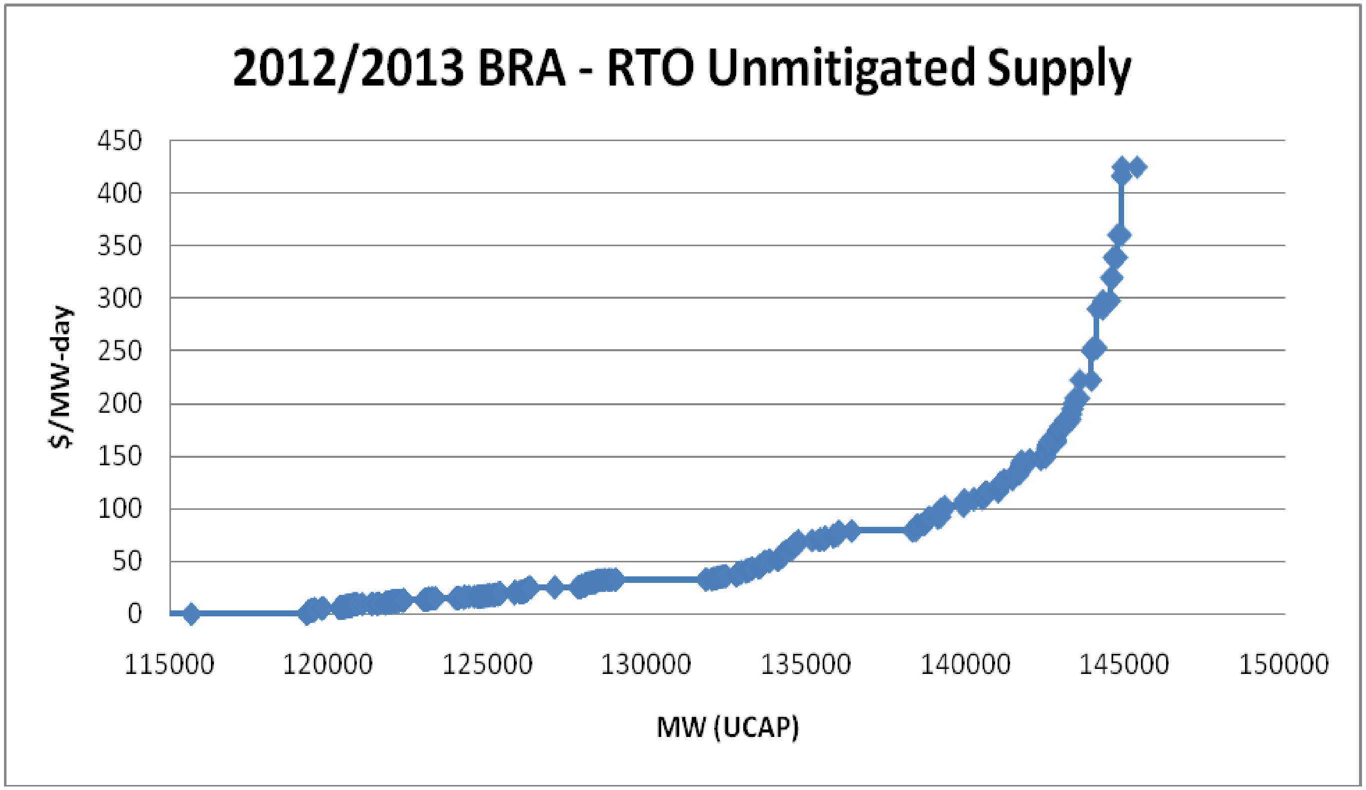
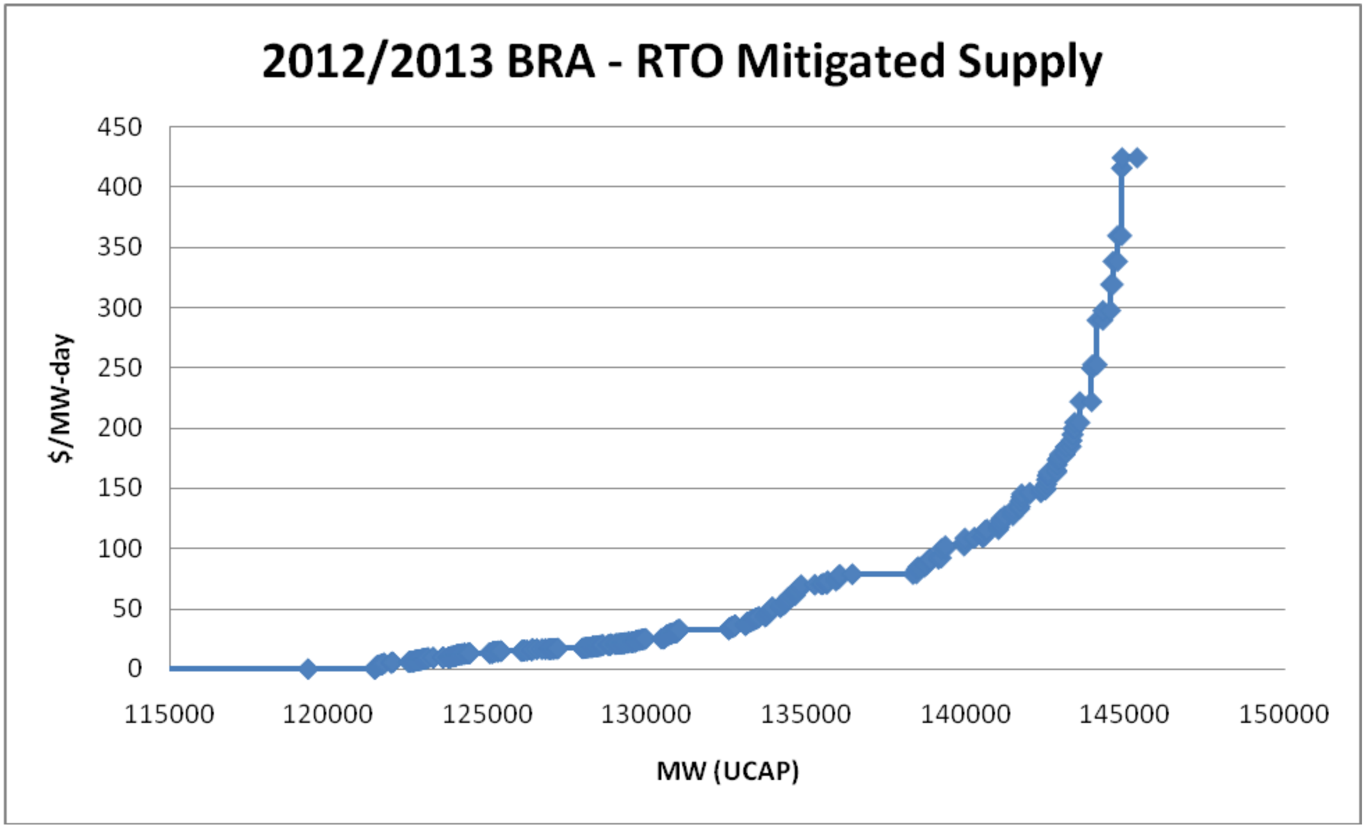


Figure 3 - Supply Curve for the RTO (Mitigated)

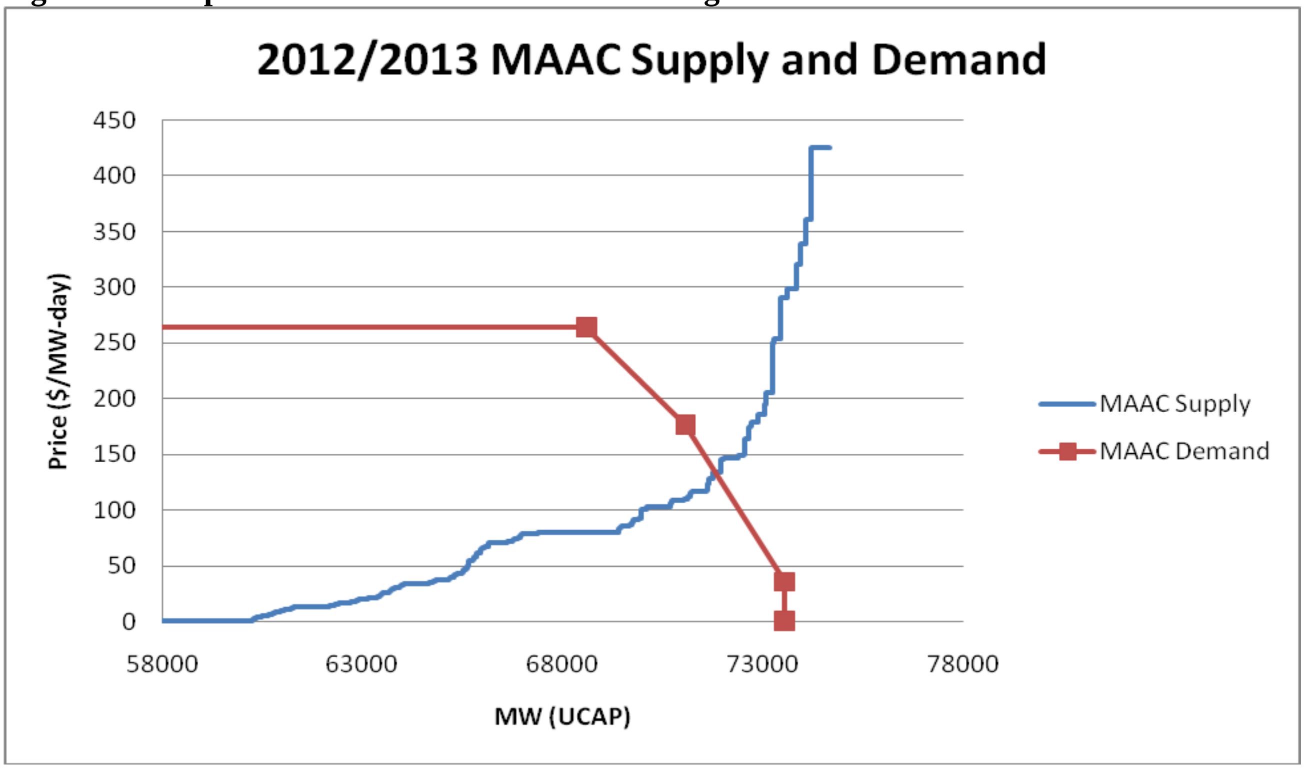


MAAC Clearing Price

Although previously not binding in the 2011/12 BRA, the MAAC LDA was a constrained LDA in the 2012/2013 Base Residual Auction as a result of transmission limitations into the MAAC region. The MAAC region contains the PN, PL, ME zones in addition to the zones contained within the EMAAC and SWMAAC LDAs. The clearing results for MAAC were determined by the intersection of the Supply Curve with the MAAC LDA Variable Resource Requirement (VRR) Curve at a price of $133.37/MW-day. The 65,452.3 MW of UCAP cleared in the LDA included 4,723.8 MW of demand resources and 179.9 MW of energy efficiency resources.

Figure 4 graphically depicts the clearing of the MAAC LDA.

Figure 4 – Graphical Illustration of MAAC Clearing Results for 2012/2013 Base Residual Auction



The unmitigated supply curve for the MAAC LDA is depicted in Figure 5. The plot represents the UCAP offered by all participants at the EFORd and price submitted with that offer. Figure 6 shows the mitigated supply curve for the MAAC. The mitigated supply curve was used to clear the 2012/13 Base Residual Auction as all suppliers failed the Market Structure Test.

Figure 5 - Supply Curve for the MAAC (Unmitigated)

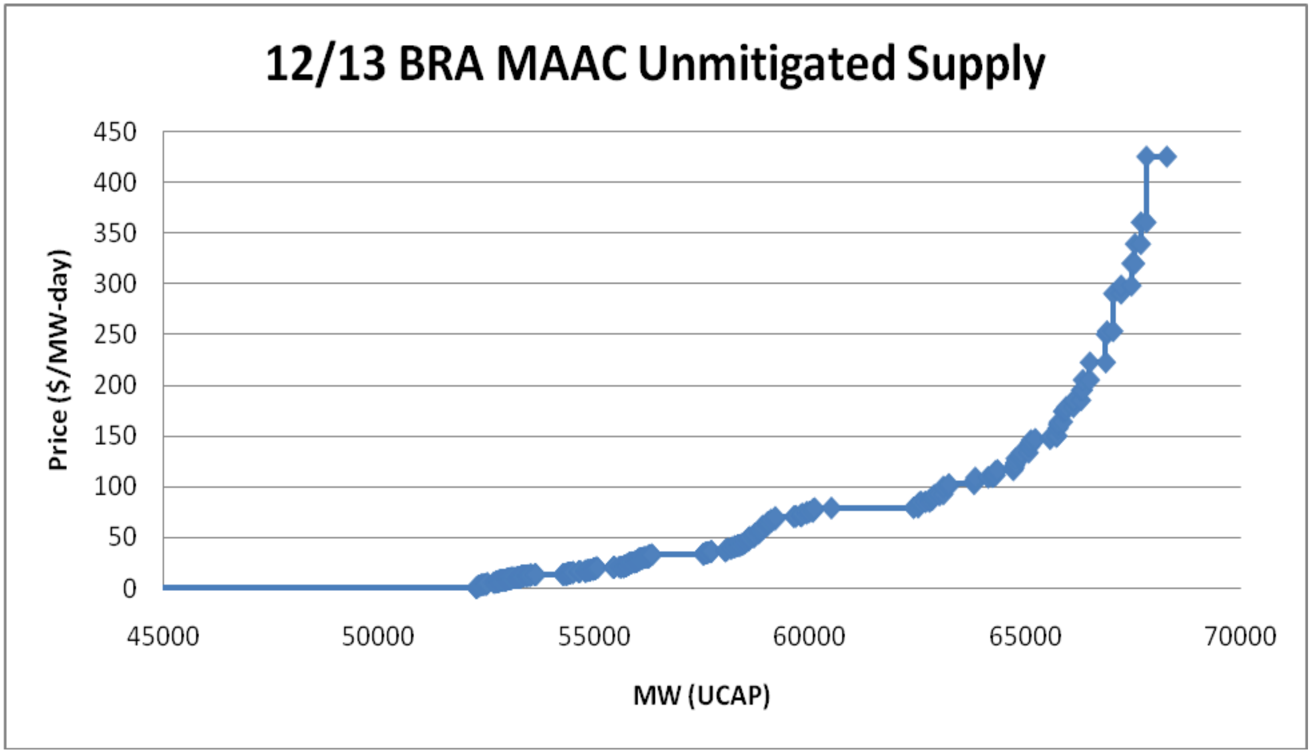
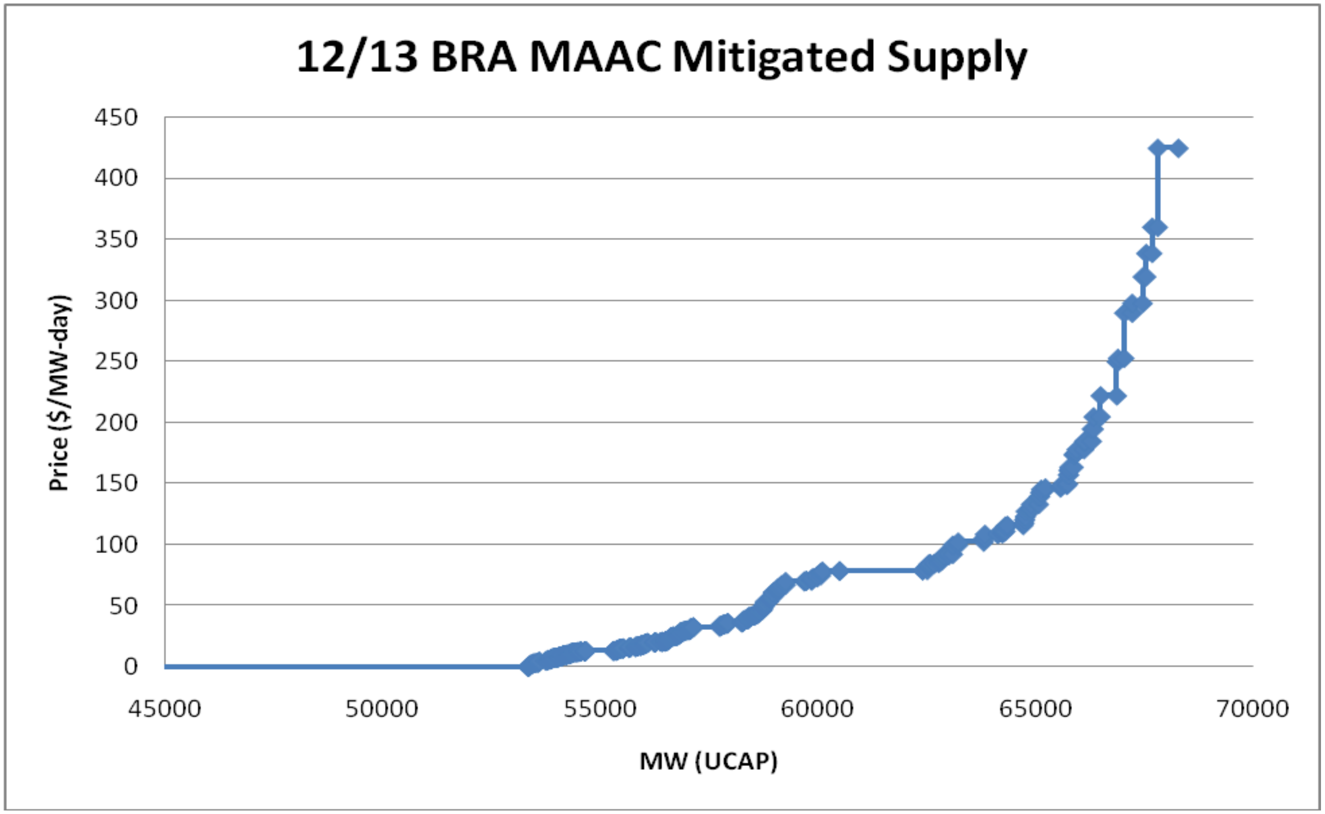


Figure 6 - Supply Curve for the MAAC (Mitigated)



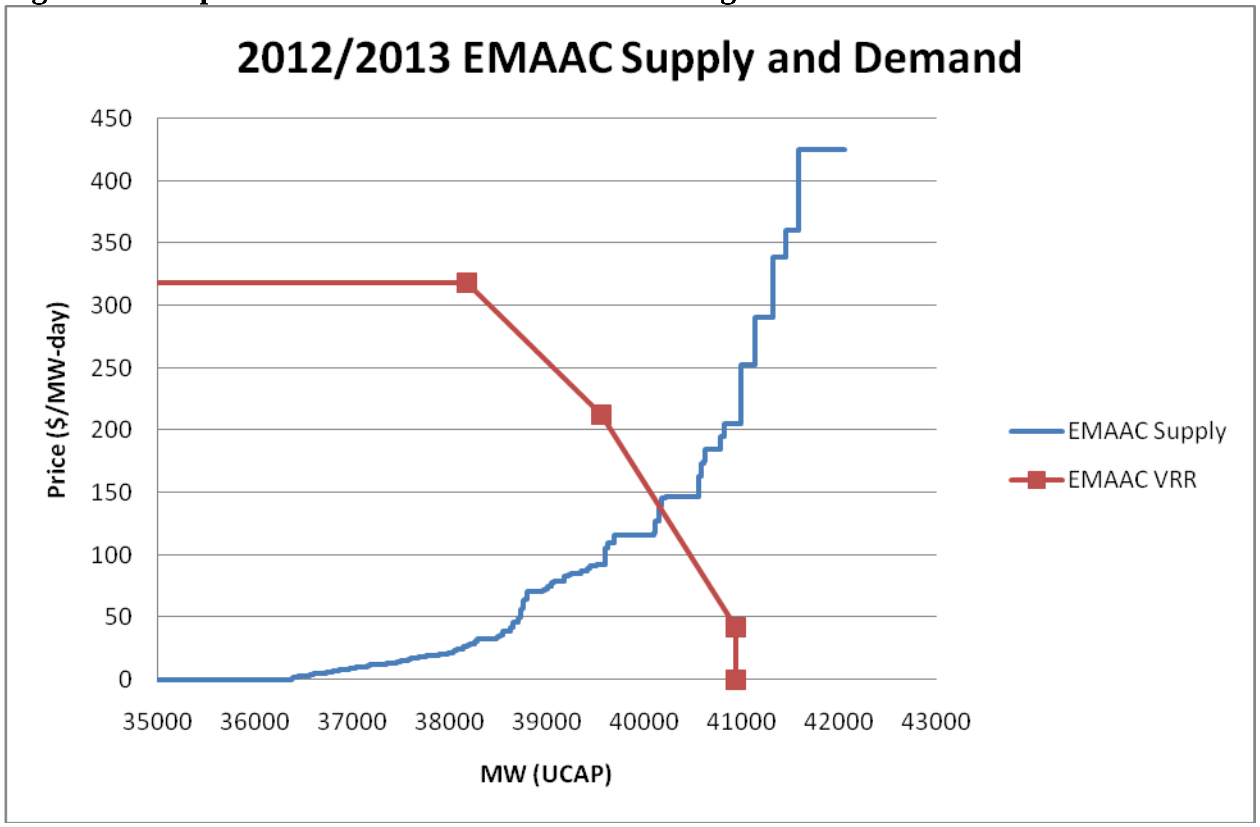
SWMAAC Clearing Price

Though modeled in the 2012/2013 BRA, the SWMAAC region, comprised of the BGE and PEPCO transmission zones, was not a binding LDA in this auction. As SWMAAC resources are also located within the larger MAAC region, cleared resources from SWMAAC will be paid the MAAC resource clearing price of $133.37/MW-day.

EMAAC Clearing Price

EMAAC was a binding LDA in the RPM auction clearing as a result of transmission limitations into the EMAAC region. The EMAAC region is comprised of the AECO, JCPL, PECO, RECO, DPL, and PSEG transmission zones. The clearing results for EMAAC were determined by the intersection of the Supply Curve with the EMAAC LDA Variable Resource Requirement (VRR) Curve at a price of $139.73/MW-day. The 31,080.2 MW of UCAP cleared in the LDA included 1,638.5 MW of demand resources and 20 MW of energy efficiency resources.

Figure 7 - Graphical Illustration of EMAAC Clearing Results for 2012/13 Base Residual Auction



The unmitigated supply curve for EMAAC is depicted below in Figure 8. The plot represents the UCAP offered by all resources in the LDA at the EFORd and price submitted with that offer. Figure 9 shows the mitigated supply curve for EMAAC. The supply curve depicted in Figure 7 was used to clear the 2012/2013 Base Residual Auction. It contains both mitigated and unmitigated offers as some suppliers passed the Market Structure Test in the EMAAC LDA.

Figure 8 - Supply Curve for EMAAC (Unmitigated)

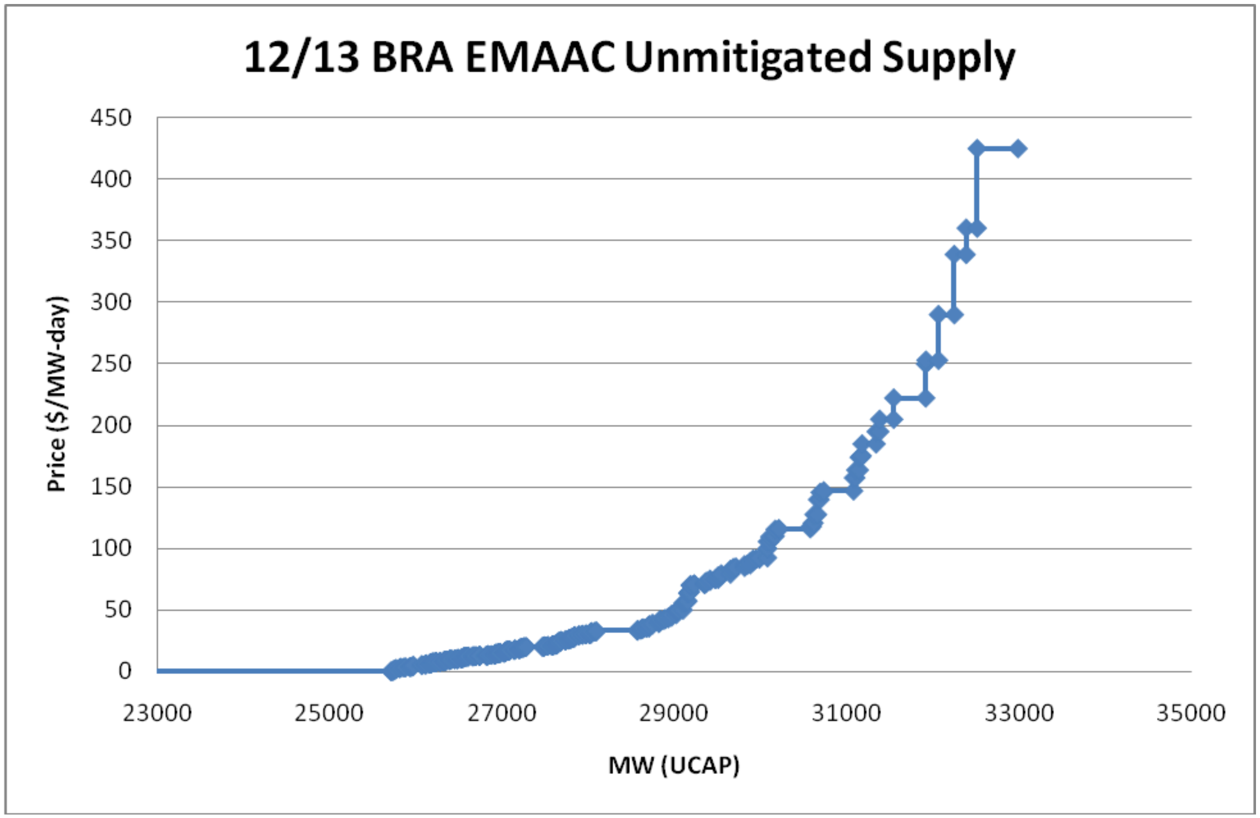
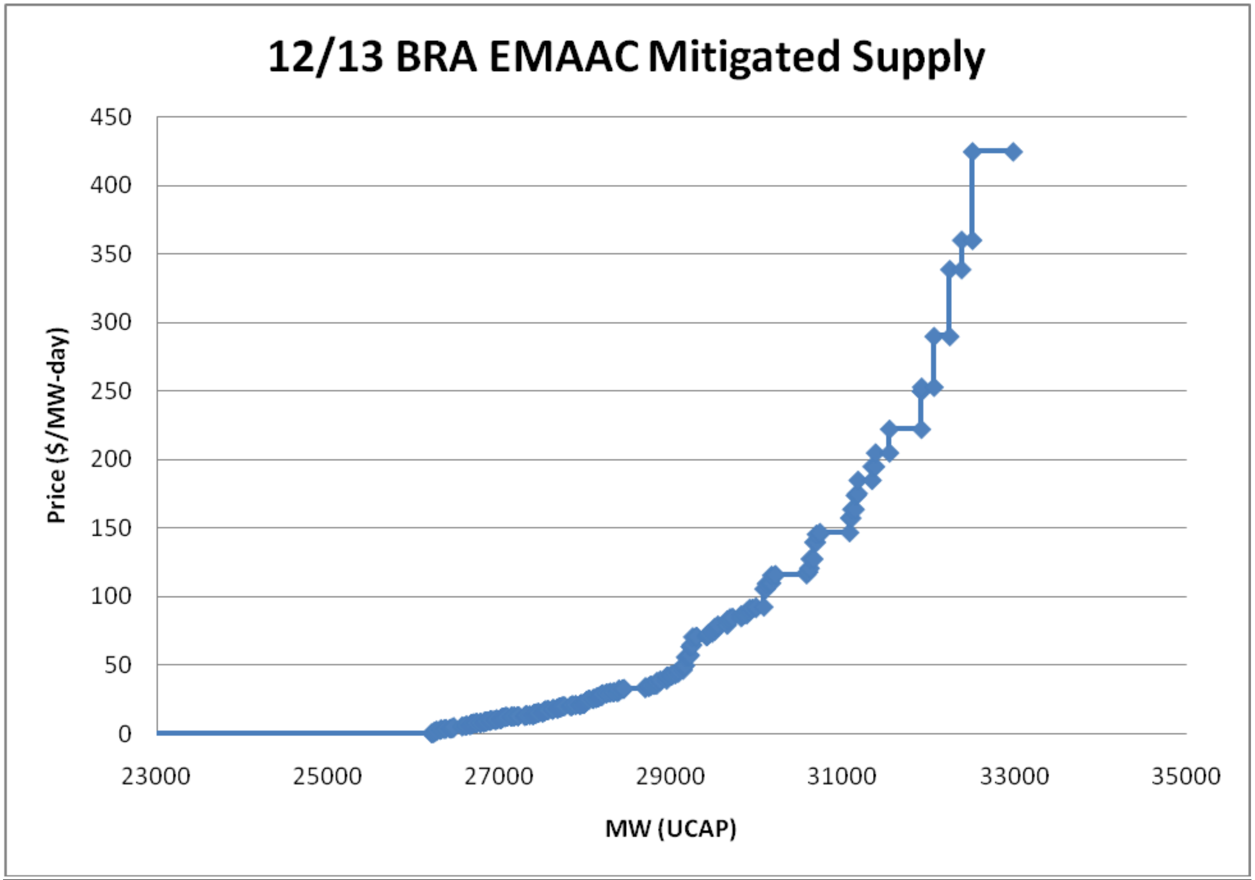


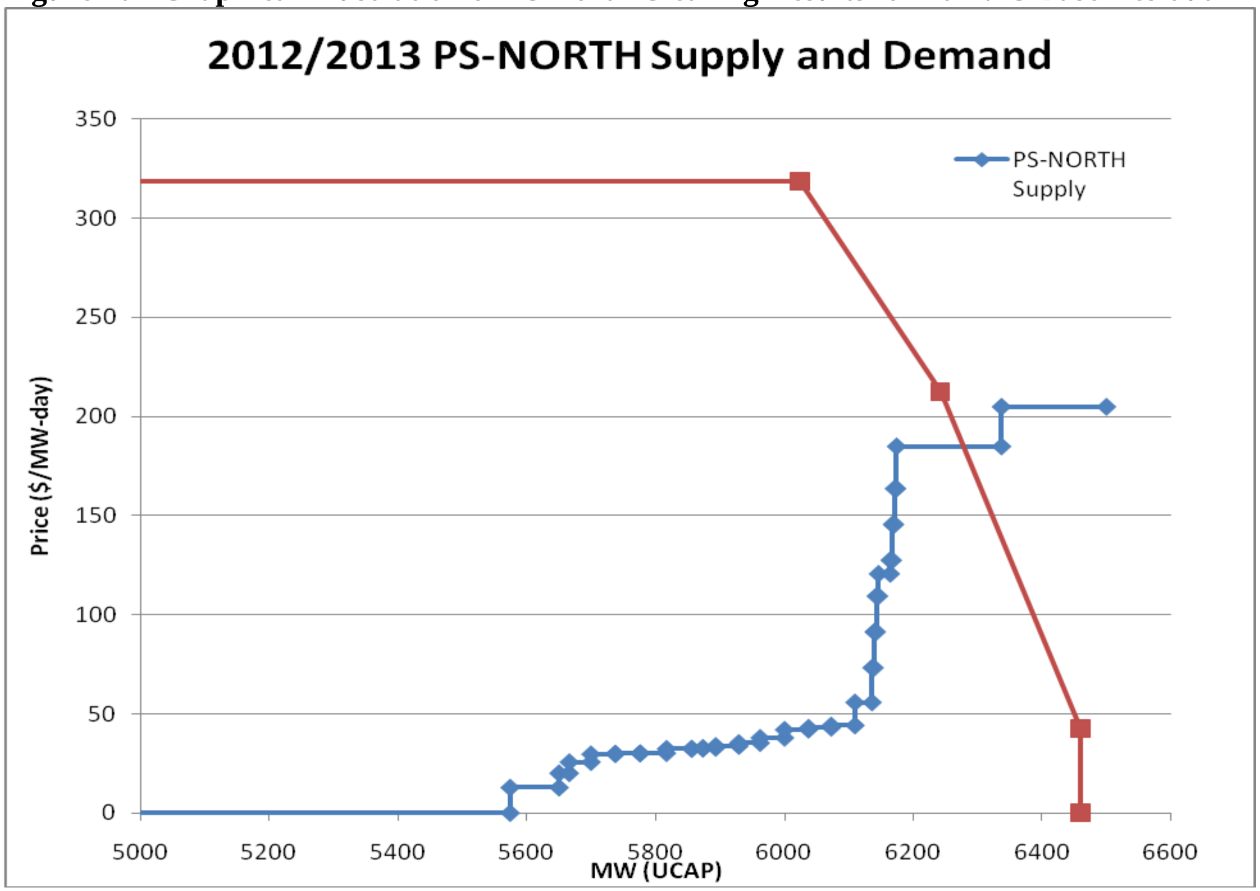
Figure 9 - Supply Curve for EMAAC (Mitigated)



PS North Clearing Price

Modeled for the first time in 2012/2013, PS-North was a binding LDA in the RPM auction clearing as a result of transmission limitations into the PS-North region. The PS-North LDA is contained wholly within the PSEG transmission zone. The clearing results for PS-North were determined by an intersection of the supply and the PS-North LDA Variable Resource Requirement (VRR) Curve at a price of $185.00/MW-day. The 3521.9 MW of UCAP cleared in the LDA included 67.6 MW of demand resources and 0.9 MW of energy efficiency resources.

Figure 10 - Graphical Illustration of PS North Clearing Results for 2012/13 Base Residual Auction

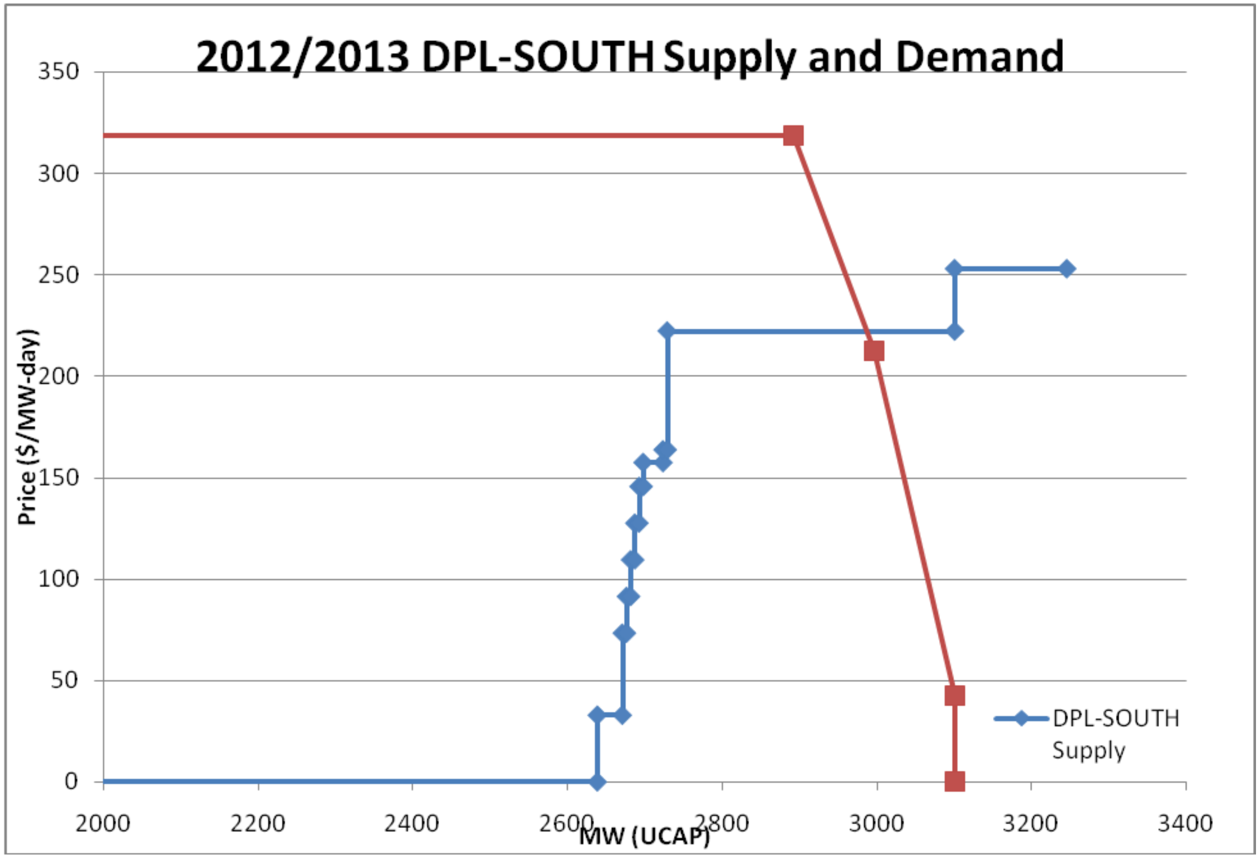


The unmitigated supply curve for PS North is depicted below in Figure 11. The plot represents the UCAP offered by all resources in the LDA at the EFORd and price submitted with that offer. Figure 12 shows the mitigated supply curve for PS North. The mitigated supply curve was used to clear the 2012/2013 Base Residual Auction.

DPL South Clearing Price

DPL-South was a binding LDA in the 2012/2013 RPM auction clearing as a result of transmission limitations into the DPL-South region. The DPL-South LDA is contained wholly within the DPL transmission zone. The clearing results for DPL-South were determined by the intersection of the Supply Curve with the DPL-South LDA Variable Resource Requirement (VRR) Curve at a price of $222.30/MW-day. The 1241.5 MW of UCAP cleared in the LDA included 64.6 MW of demand resources and 0.0 MW of energy efficiency resources.

Figure 13 - Graphical Illustration of DPL South Clearing Results for 2012/13 Base Residual Auction



The unmitigated supply curve for DPL South is depicted below in Figure 14. The plot represents the UCAP offered by all resources in the LDA at the EFORd and price submitted with that offer. Figure 15 shows the mitigated supply curve for DPL South. The mitigated supply curve was used to clear the 2012/2013 Base Residual Auction.

Figure 14 - Supply Curve for DPL South (Unmitigated)

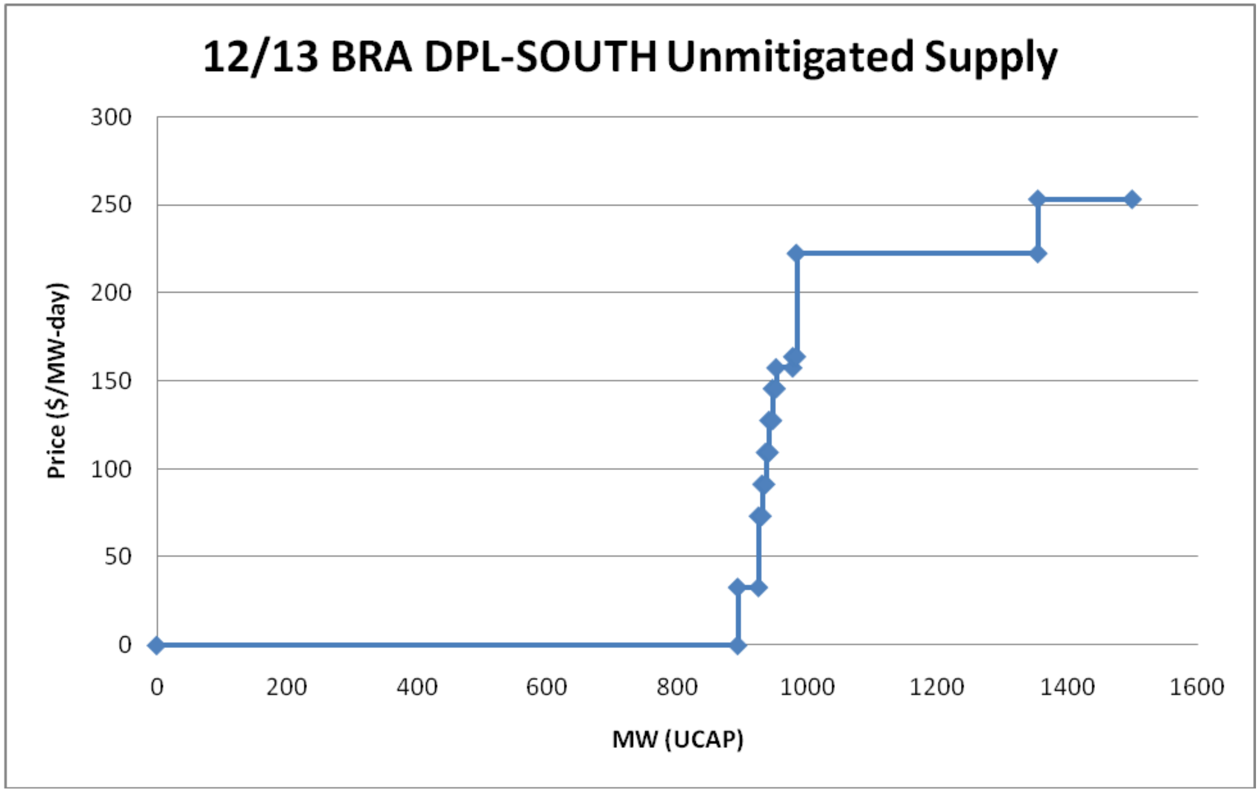


Figure 15 - Supply Curve for DPL South (Mitigated)

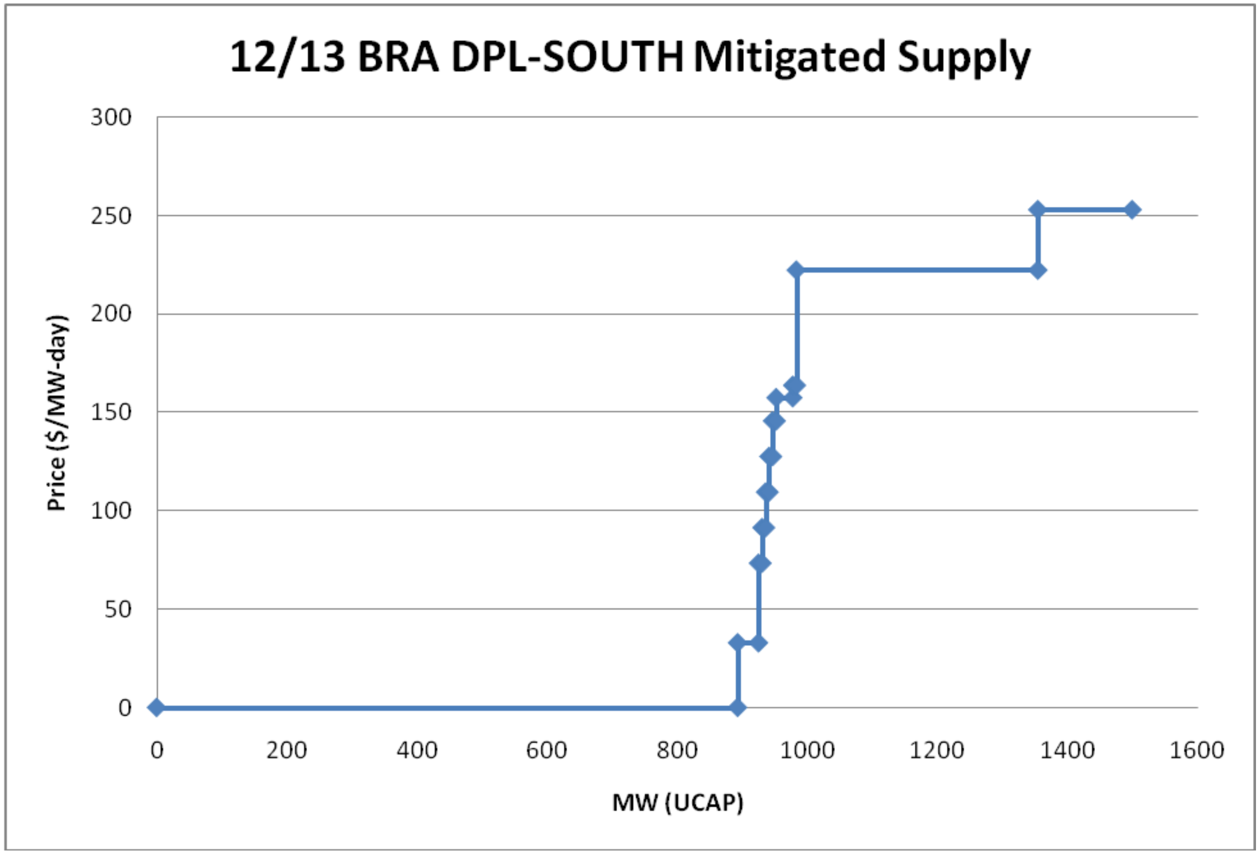
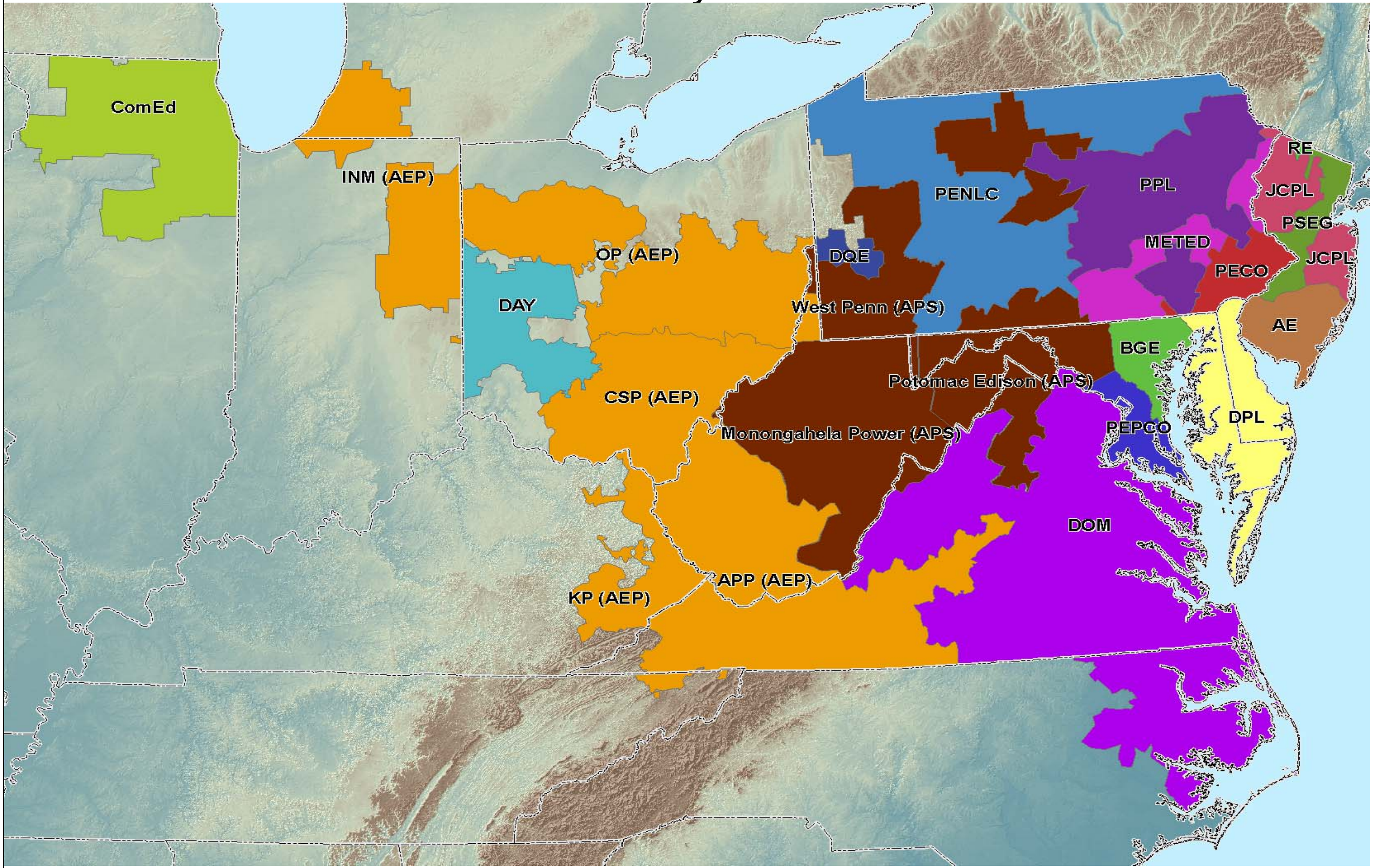


Exhibit RMF-3

PJM Load Forecast Report
January 2008



Prepared by PJM Capacity Adequacy Planning Department

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TERMS AND ABBREVIATIONS USED IN THIS REPORT

AE	Atlantic Electric zone (part of Pepco Holdings, Inc)
AEP	American Electric Power zone (incorporated 10/1/2004)
APP	Appalachian Power, sub-zone of AEP
APS	Allegheny Power zone (incorporated 4/1/2002)
Base Load	Average peak load on non-holiday weekdays with no heating or cooling load. Base load is insensitive to weather.
BGE	Baltimore Gas & Electric zone
COMED	Commonwealth Edison zone (incorporated 5/1/2004)
Contractually Interruptible	Load Management from customers responding to direction from a control center
Cooling Load	The weather-sensitive portion of summer peak load
CSP	Columbus Southern Power, sub-zone of AEP
Direct Control	Load Management achieved directly by a signal from a control center
DAY	Dayton Power & Light zone (incorporated 10/1/2004)
DLCO	Duquesne Lighting Company zone (incorporated 1/1/2005)
DPL	Delmarva Power & Light zone (part of Pepco Holdings, Inc)
FE/GPU	The combination of First Energy's Jersey Central Power & Light, Metropolitan Edison, and Pennsylvania Electric zones (formerly GPU)
Heating Load	The weather-sensitive portion of winter peak load
INM	Indiana Michigan Power, sub-zone of AEP
JCPL	Jersey Central Power & Light zone
KP	Kentucky Power, sub-zone of AEP
METED	Metropolitan Edison zone
MP	Monongahela Power, sub-zone of APS
Net Energy	Net Energy for Load, measured as net generation of main generating units plus energy receipts minus energy deliveries
OP	Ohio Power, sub-zone of AEP

PECO	PECO Energy zone
PED	Potomac Edison, sub-zone of APS
PEPCO	Potomac Electric Power zone (part of Pepco Holdings, Inc)
PL	PPL Electric Utilities, sub-zone of PLGroup
PLGroup/PLGRP	Pennsylvania Power & Light zone
PENLC	Pennsylvania Electric zone
PS	Public Service Electric & Gas zone
RECO	Rockland Electric (East) zone (incorporated 3/1/2002)
UGI	UGI Utilities, sub-zone of PLGroup
WP	West Penn Power, sub-zone of APS
Zone	Areas within the PJM Control Area, as defined in the PJM Reliability Assurance Agreement

2008 PJM LOAD REPORT

EXECUTIVE SUMMARY

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

2. The report includes long-term forecasts of peaks, net energy and load management for each PJM zone, region, and the total RTO.

3. Several new tables appear in this year's report: 1) Table E-1 presents annual net energy for each PJM zone, Load Deliverability Area, and the total RTO; 2) Table E-2 presents monthly net energy for each PJM zone, Load Deliverability Area, and the total RTO; and 3) Table E-3 presents monthly net energy for the combined FE/GPU and PLGrp zones. Table B-8, which presents coincident summer peak loads, has been expanded to the full 15-year forecast horizon. The former E-tables are now presented as F-1 and F-2

4. The PJM RTO weather normalized summer peak for 2007 was 136,095 MW. The projection for the 2008 PJM RTO summer peak is 137,948 MW, an increase of 1,853 MW, or 1.4%, from the 2007 normalized peak.

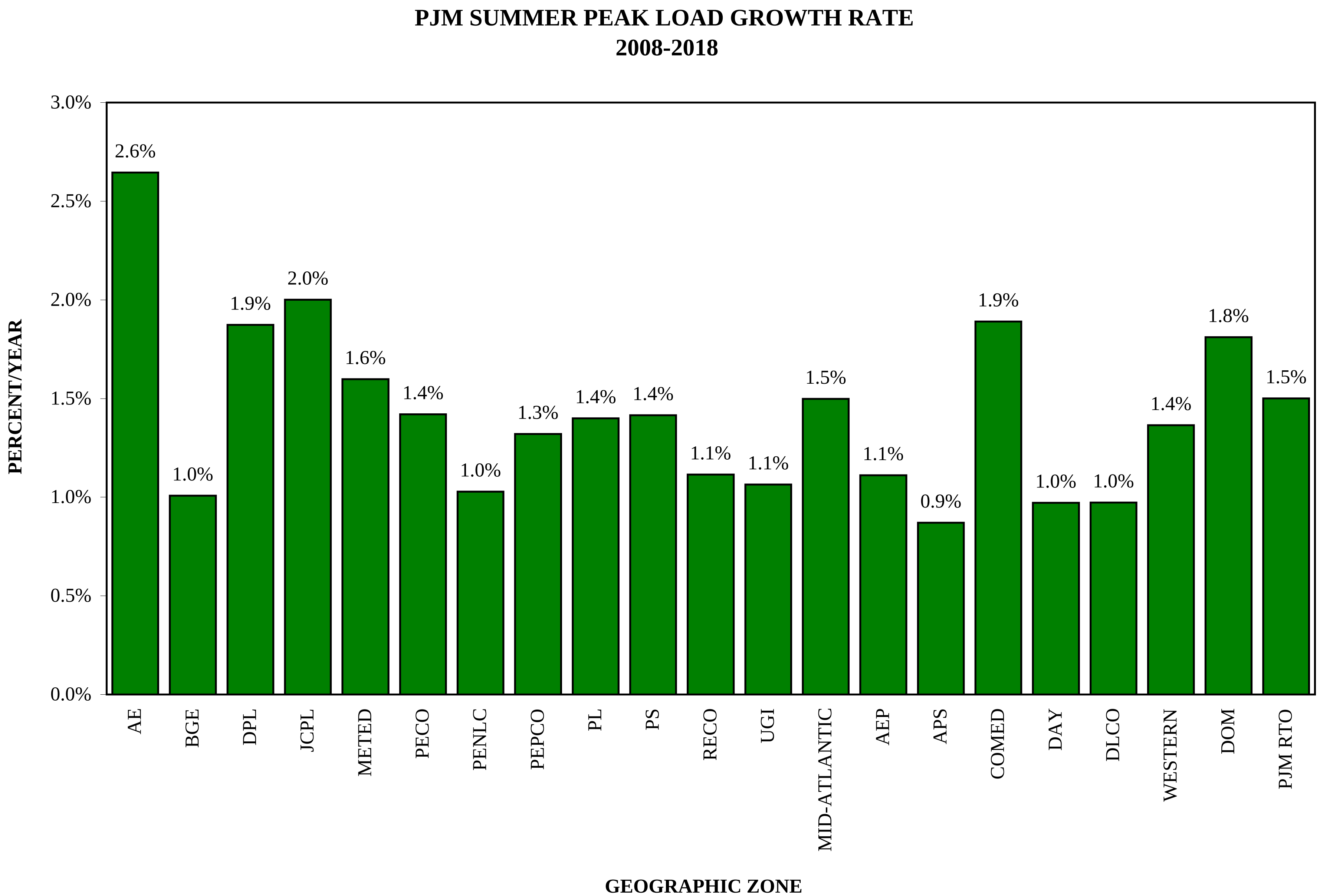
5. Summer peak load growth for PJM RTO is projected to average 1.5% per year over the next 10 years, and 1.4% over the next 15 years. The PJM RTO summer peak is forecasted to be 160,107 MW in 2018, a 10-year increase of 22,159 MW, and reaches 170,367 MW in 2023, a 15-year increase of 32,419 MW. Annualized growth rates for individual zones range from 0.9% to 2.6%.

6. Winter peak load growth for PJM RTO is projected to average 1.1% per year over the next 10- and 15-year periods. The PJM RTO winter peak load in 2017/18 is forecast to be 127,250 MW, a 10-year increase of 13,685 MW, and reaches 133,518 MW in 2022/23, a 15-year increase of 19,953 MW. Annualized growth rates for individual zones range from 0.3 to 2.3%.

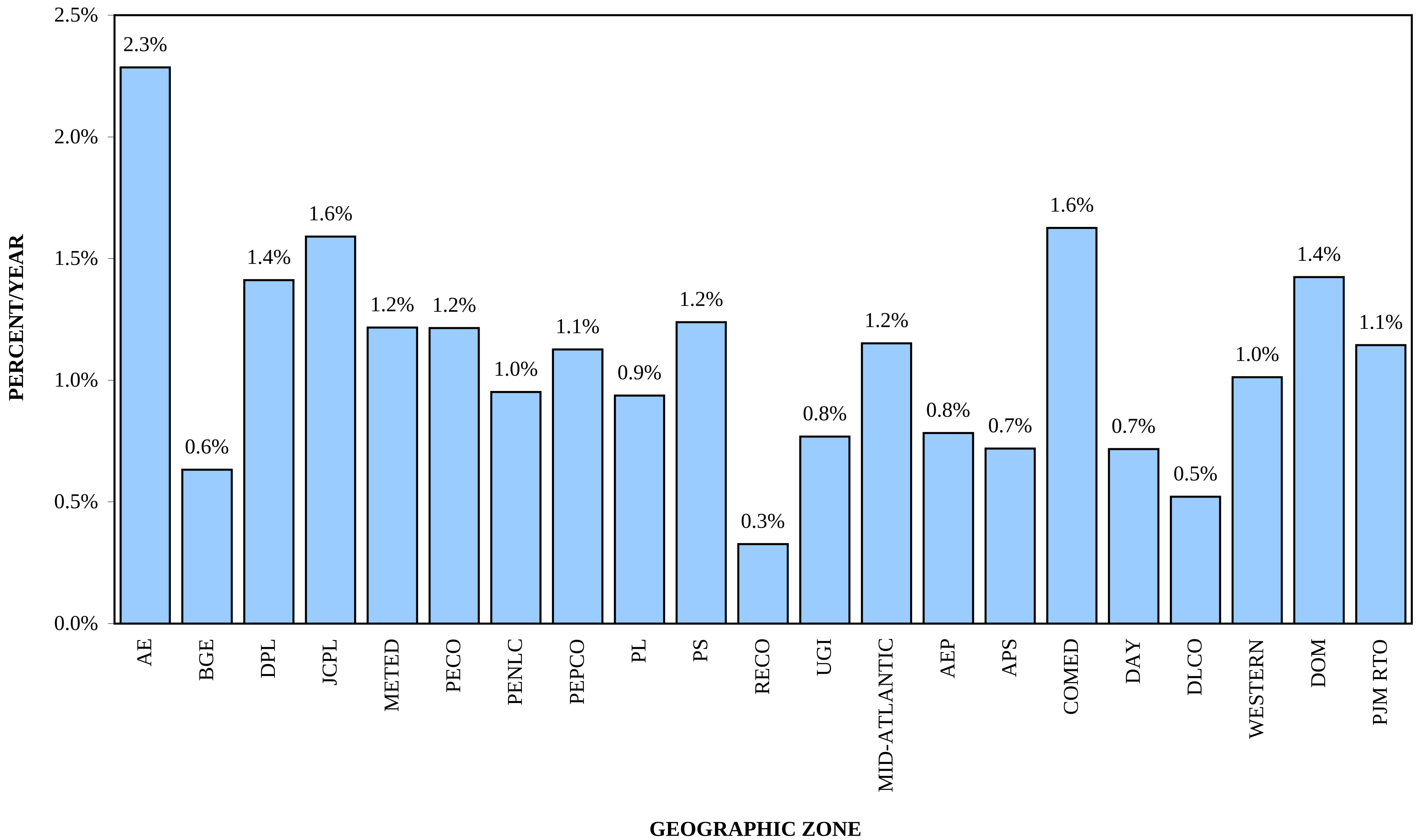
7. Based on the forecast contained within this report, the PJM RTO will continue to be summer peaking during the next 15 years.

8. The annual load factor is expected to continue a slow downward trend, consistent with increasing weather sensitivity of load. The PJM RTO load factor is forecasted to be 60.2% in 2008, dropping to 60.0% in 2018 and 59.9% in 2023.

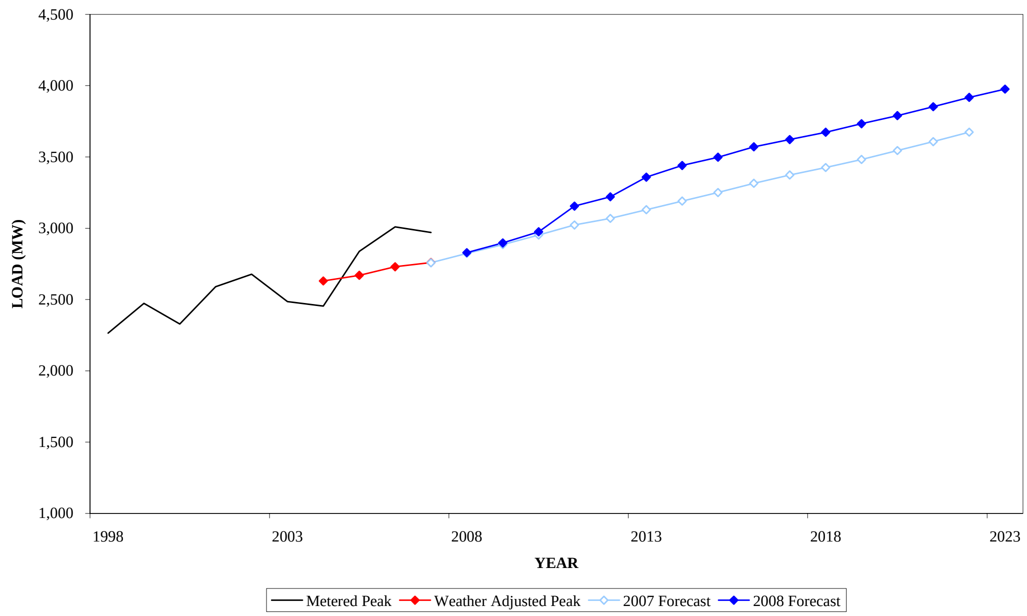
NOTE:
All compound growth rates are calculated from the first year of the forecast.


PJM SUMMER PEAK LOAD GROWTH RATE
2008-2018
PERCENT/YEAR
3.0%
2.5%
2.0%
1.5%
1.0%
0.5%
0.0%
2.6%
1.0%
1.9%
2.0%
1.6%
1.4%
1.0%
1.3%
1.4%
1.4%
1.1%
1.1%
1.5%
1.1%
0.9%
1.9%
1.0%
1.0%
1.4%
1.8%
1.5%
AE
BGE
DPL
JCPL
METED
PECO
PENLC
PEPCO
PL
PS
RECO
UGI
MID-ATLANTIC
AEP
APS
COMED
DAY
DLCO
WESTERN
DOM
PJM RTO
GEOGRAPHIC ZONE

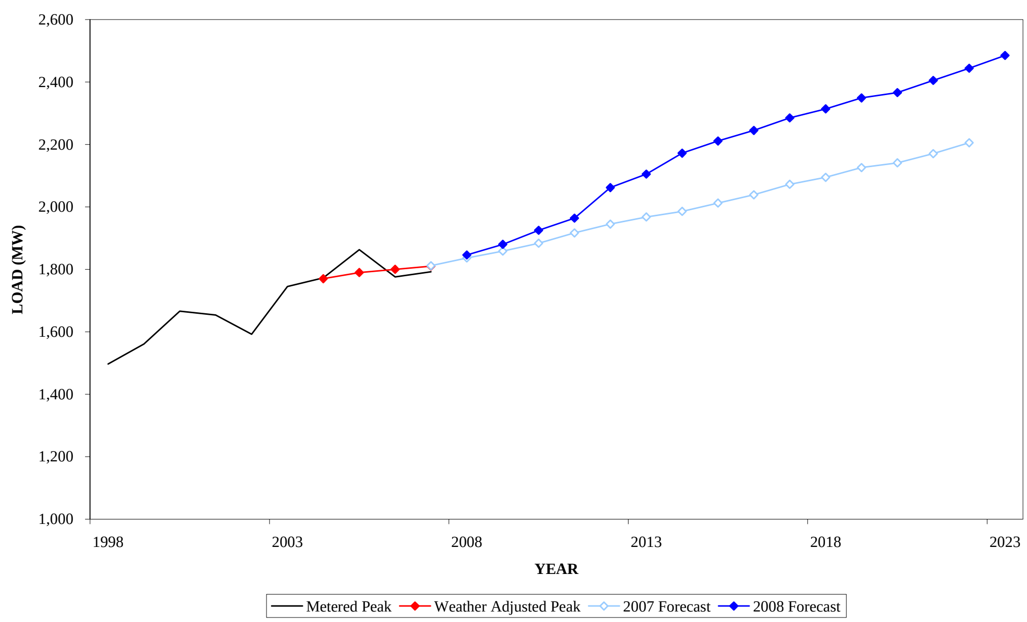
PJM WINTER PEAK LOAD GROWTH RATE
2008-2018



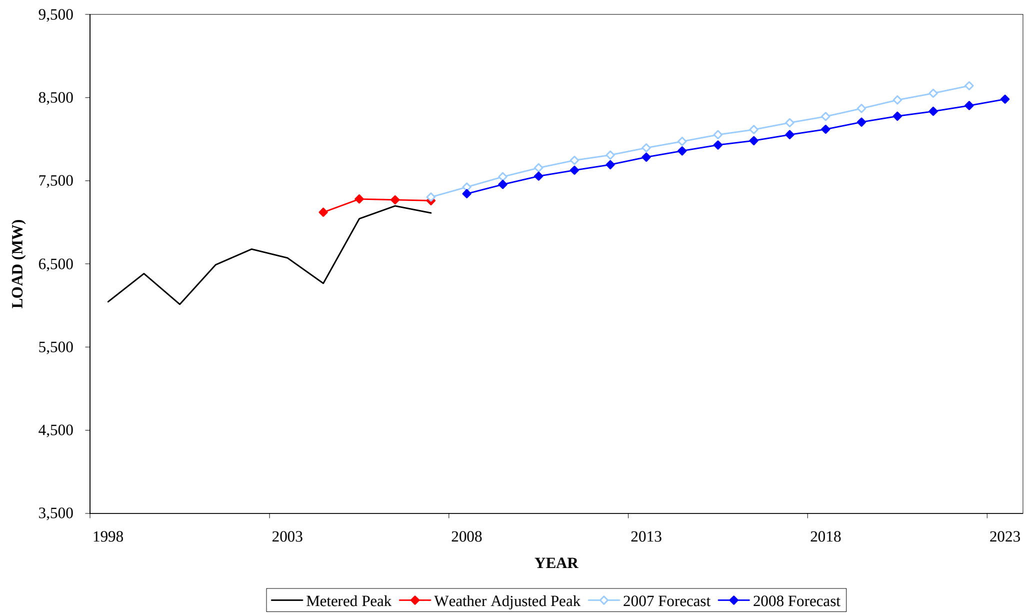
SUMMER PEAK DEMAND FOR AE GEOGRAPHIC ZONE



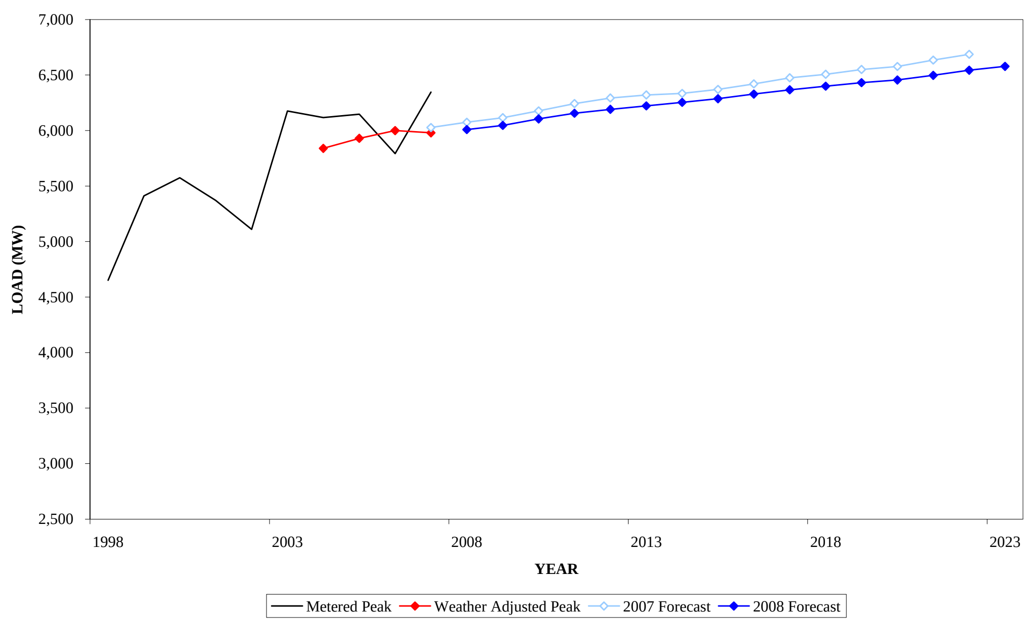
WINTER PEAK DEMAND FOR AE GEOGRAPHIC ZONE



SUMMER PEAK DEMAND FOR BGE GEOGRAPHIC ZONE



WINTER PEAK DEMAND FOR BGE GEOGRAPHIC ZONE



**SUMMER PEAK DEMAND FOR DPL
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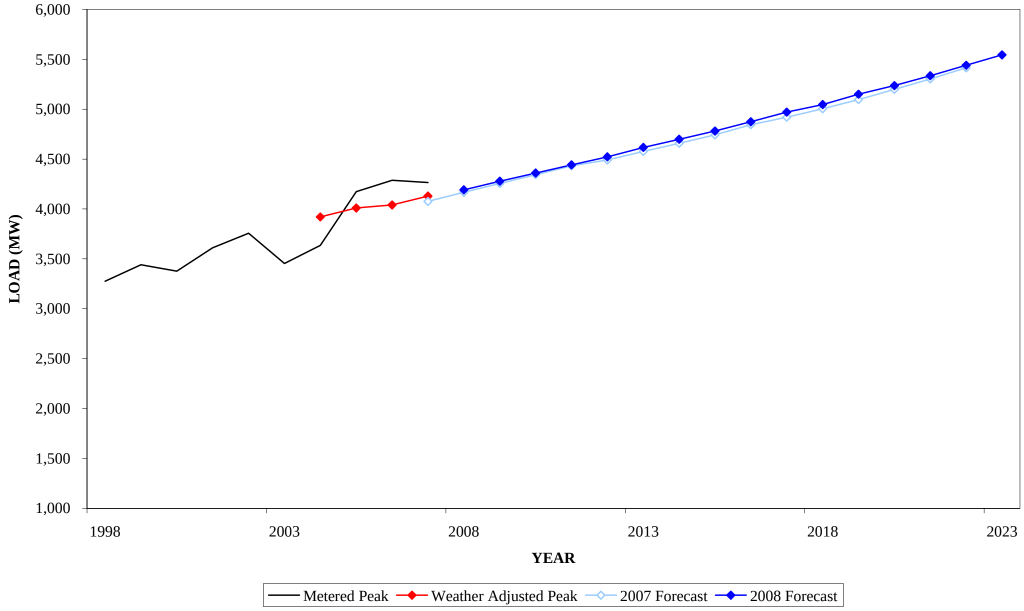
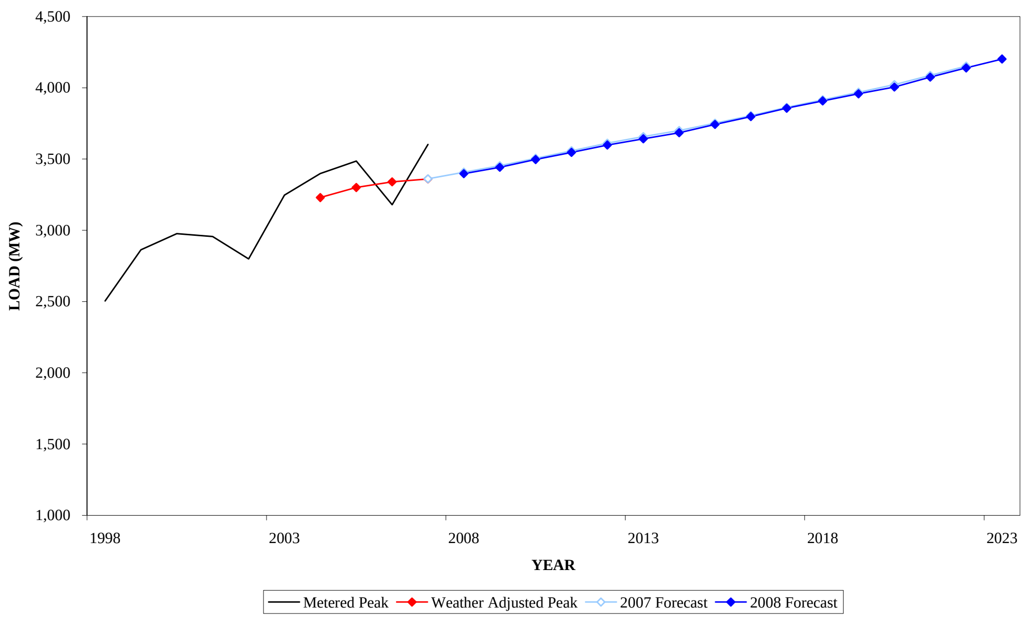


**WINTER PEAK DEMAND FOR DPL
GEOGRAPHIC ZONE**



**SUMMER PEAK DEMAND FOR JCPL
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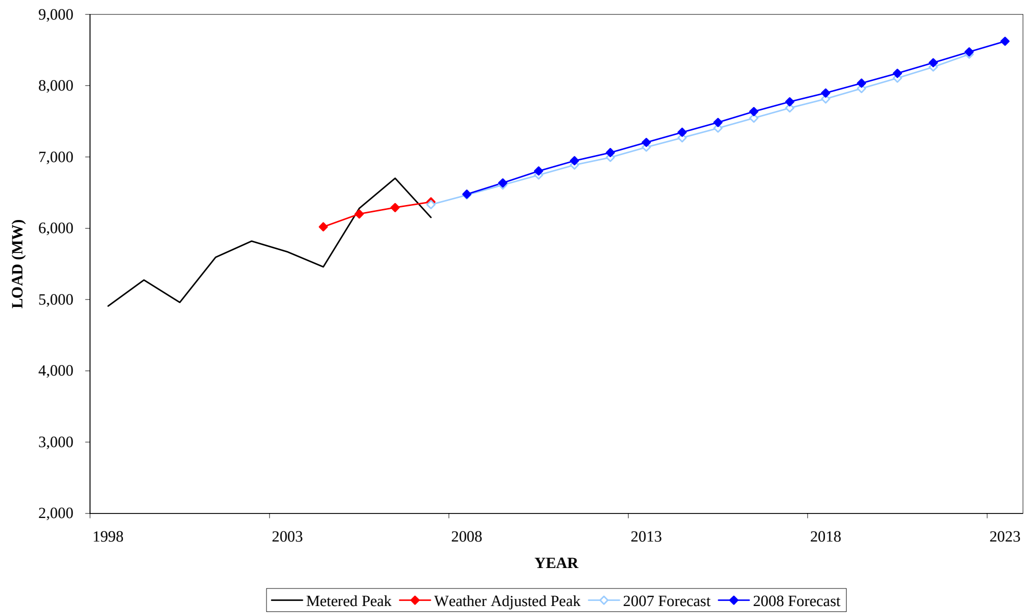

**WINTER PEAK DEMAND FOR JCPL
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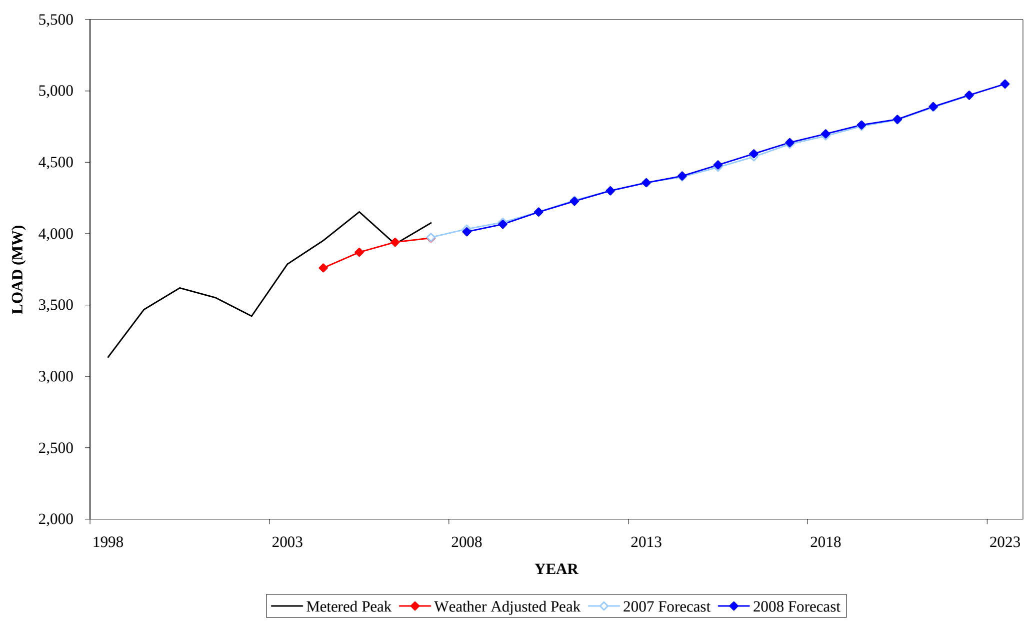
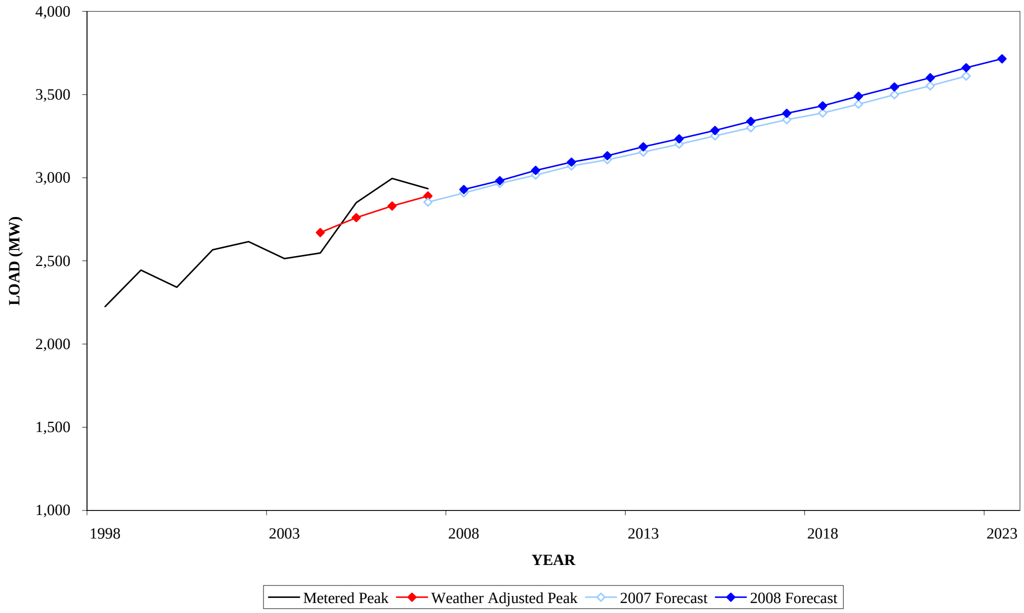


SUMMER PEAK DEMAND FOR METED GEOGRAPHIC ZONE



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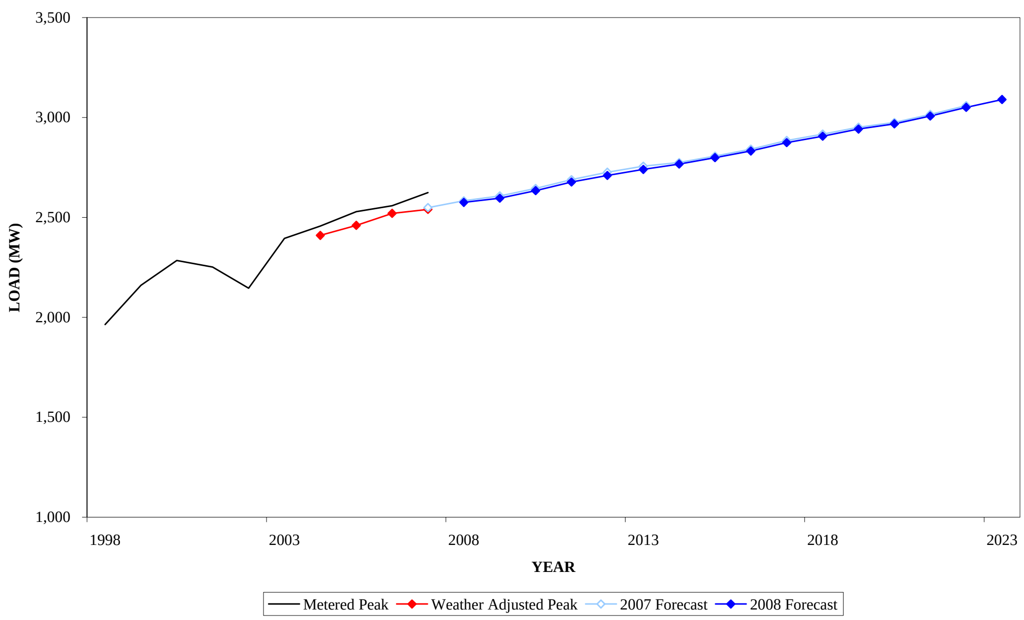
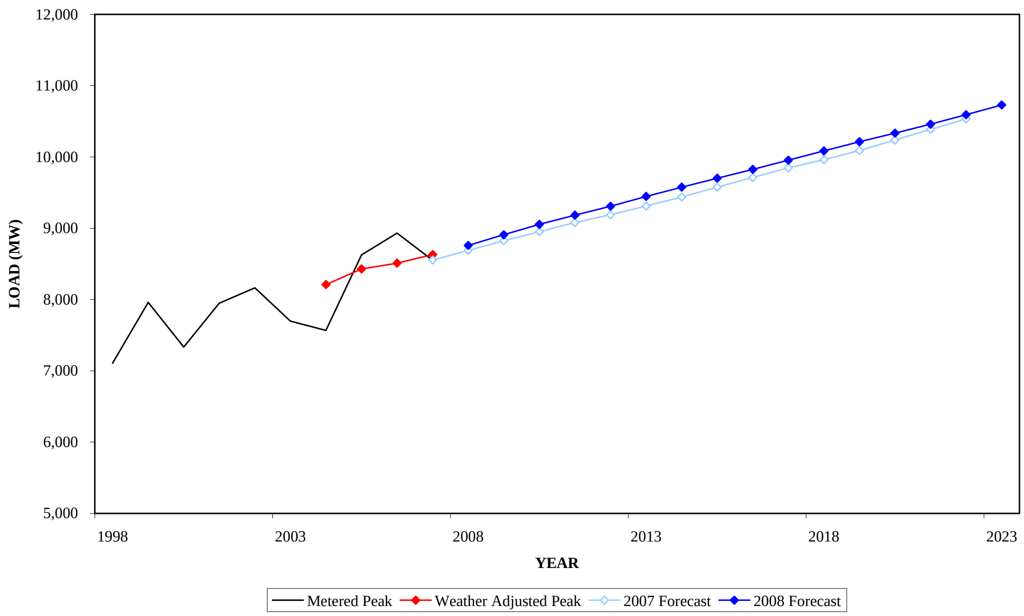
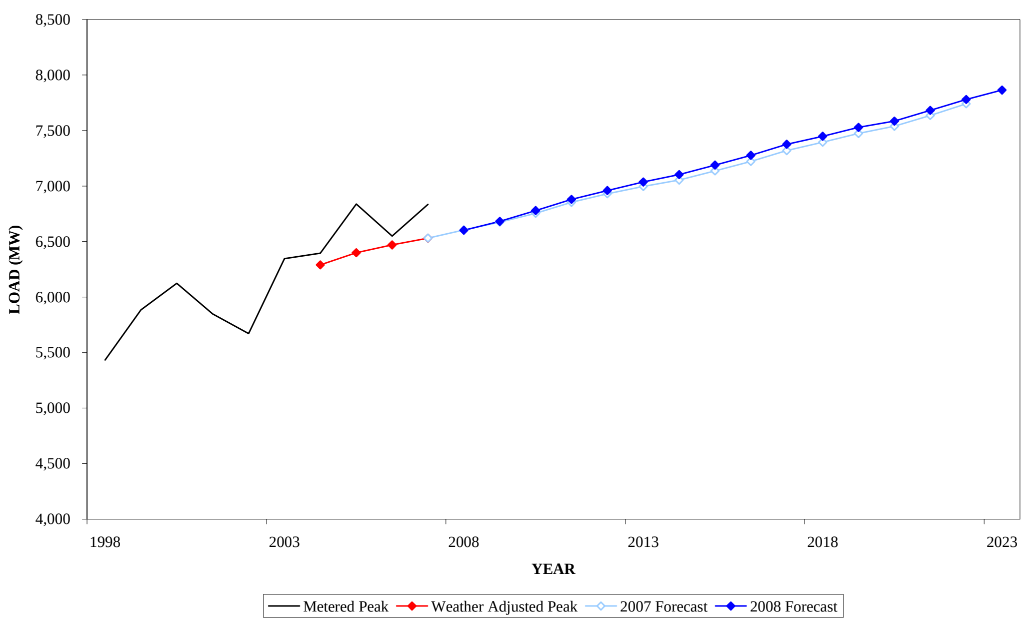


SUMMER PEAK DEMAND FOR PECO GEOGRAPHIC ZONE



WINTER PEAK DEMAND FOR PECO GEOGRAPHIC ZONE



**SUMMER PEAK DEMAND FOR PENLC
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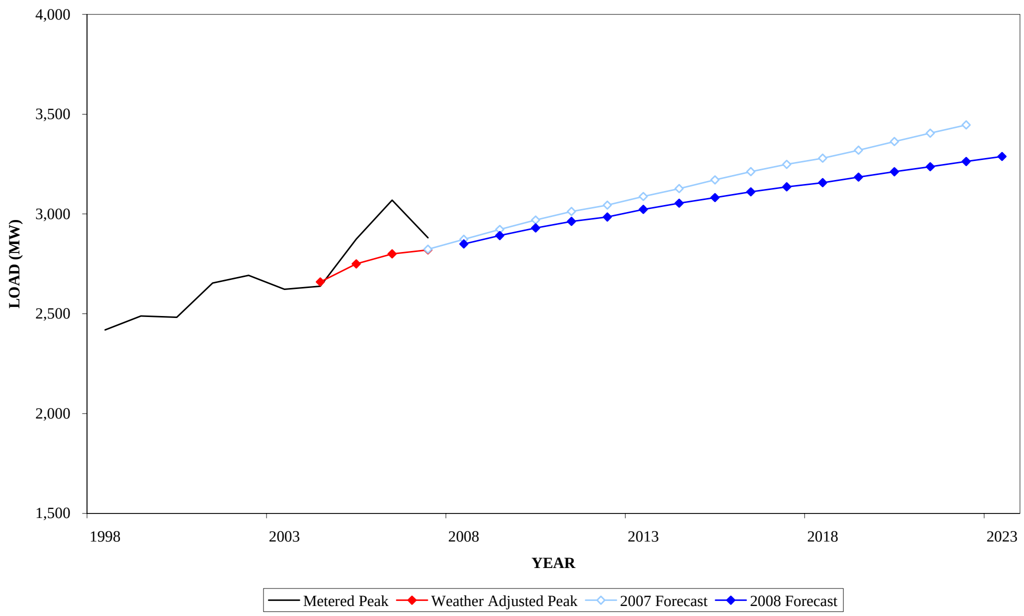
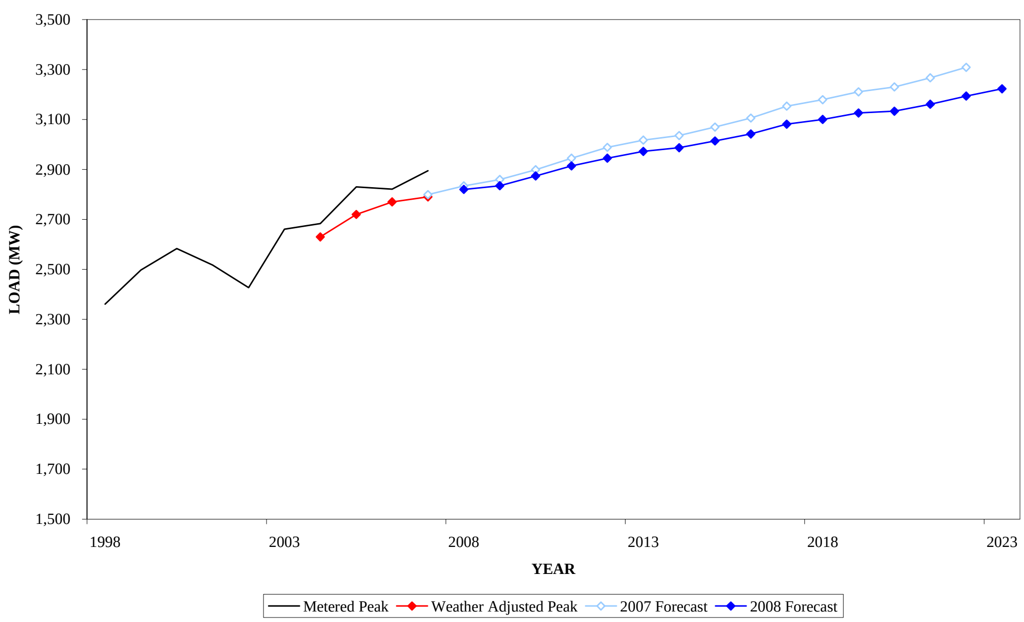
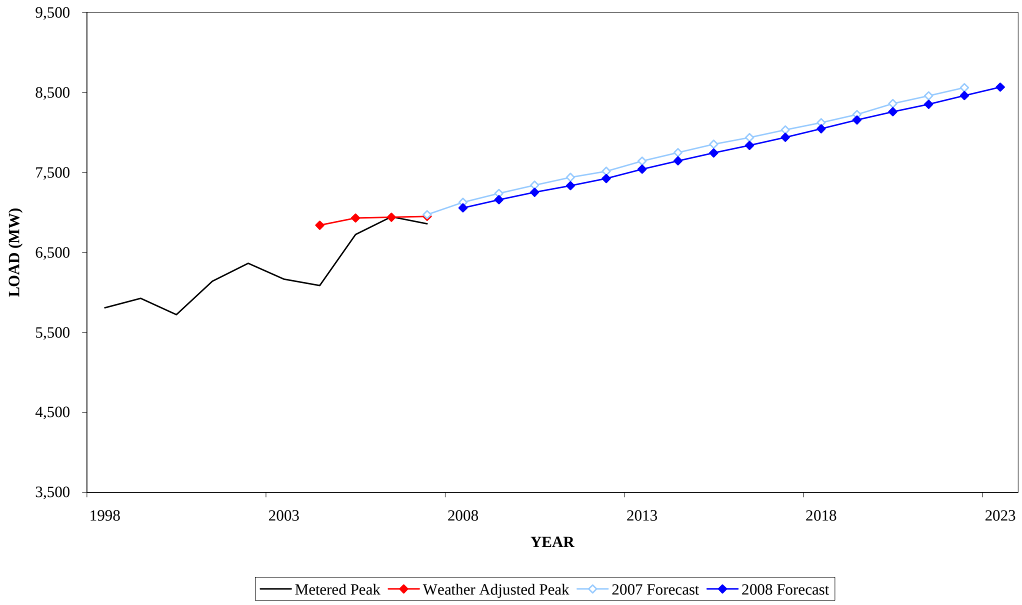


**WINTER PEAK DEMAND FOR PENLC
GEOGRAPHIC ZONE**



SUMMER PEAK DEMAND FOR PEPCO GEOGRAPHIC ZONE



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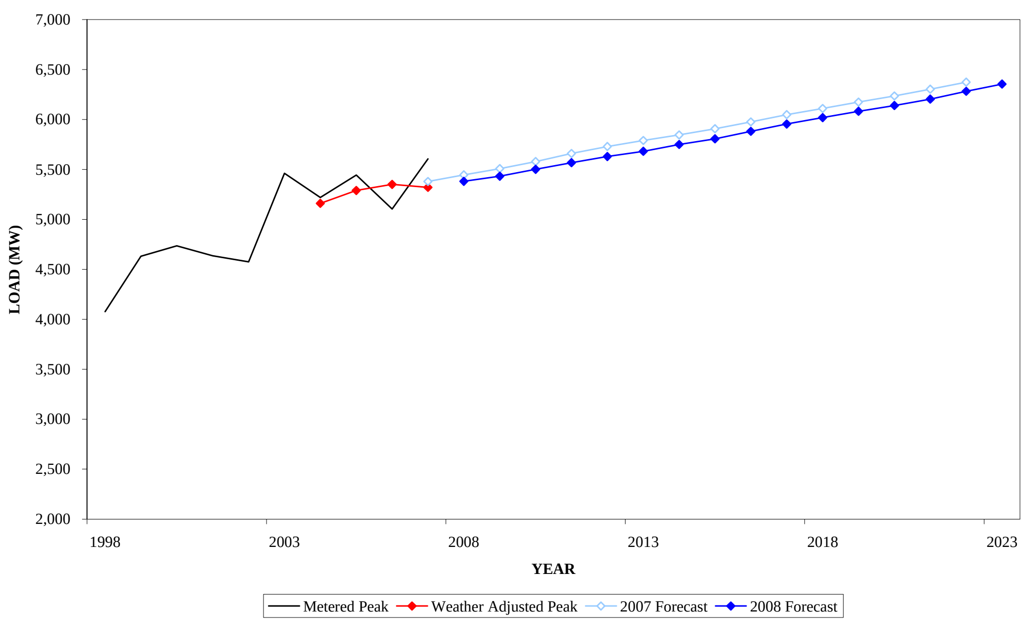
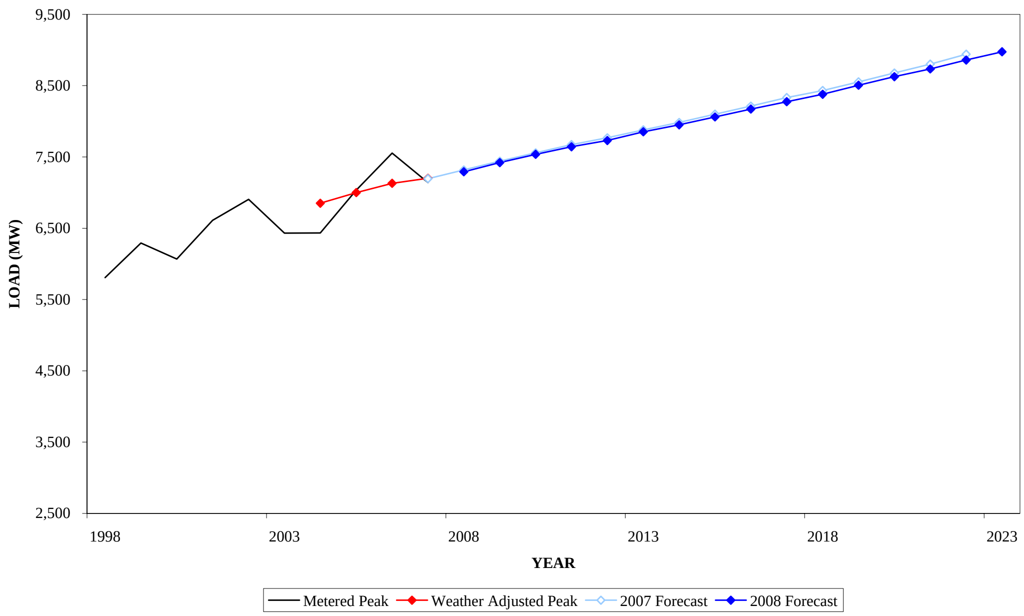


SUMMER PEAK DEMAND FOR PL GEOGRAPHIC ZONE



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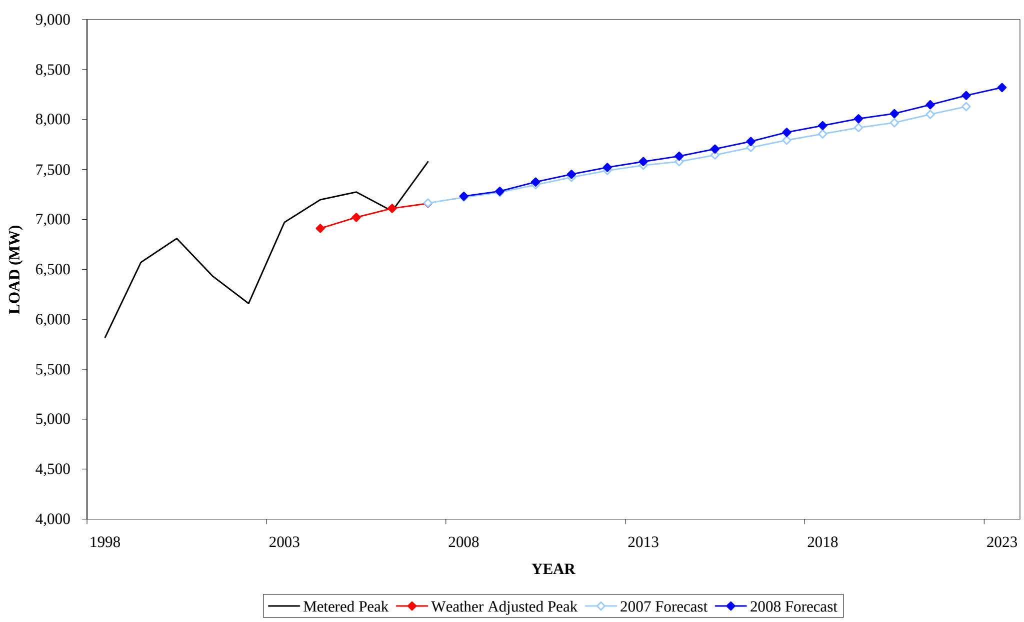

**SUMMER PEAK DEMAND FOR PS
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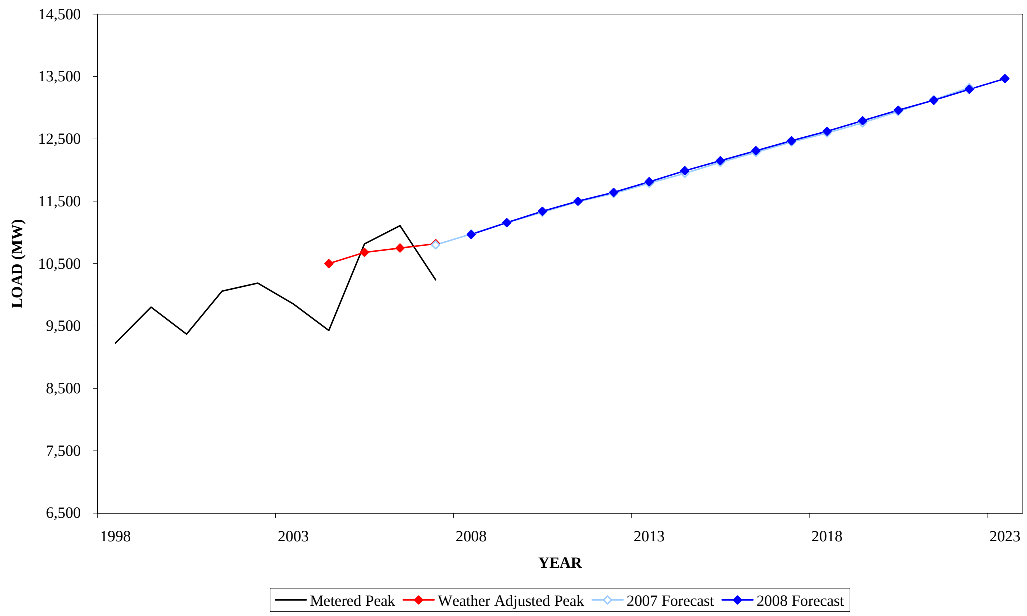

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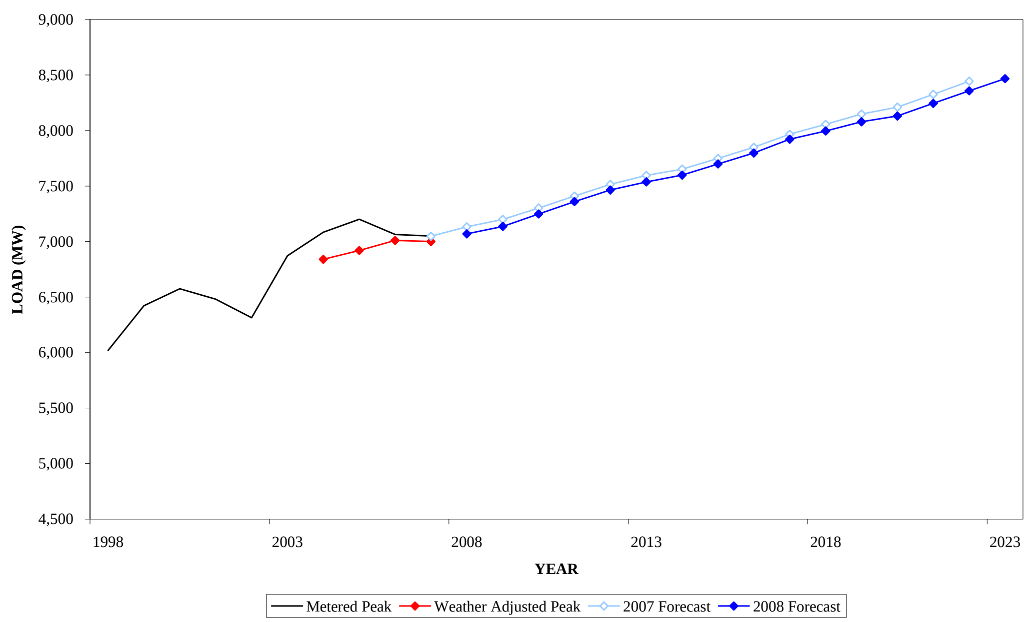
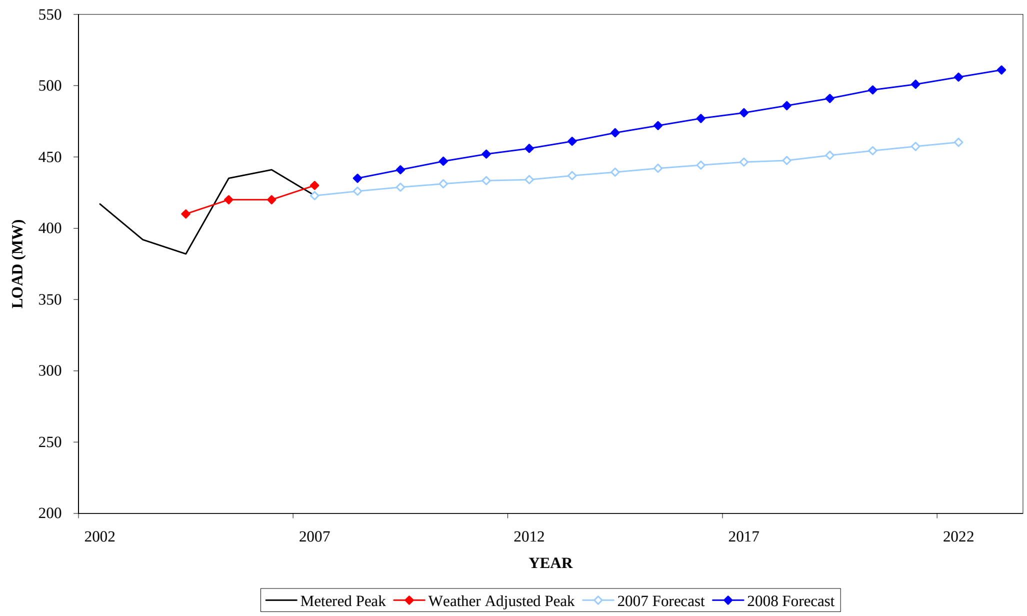


SUMMER PEAK DEMAND FOR RECO GEOGRAPHIC ZONE



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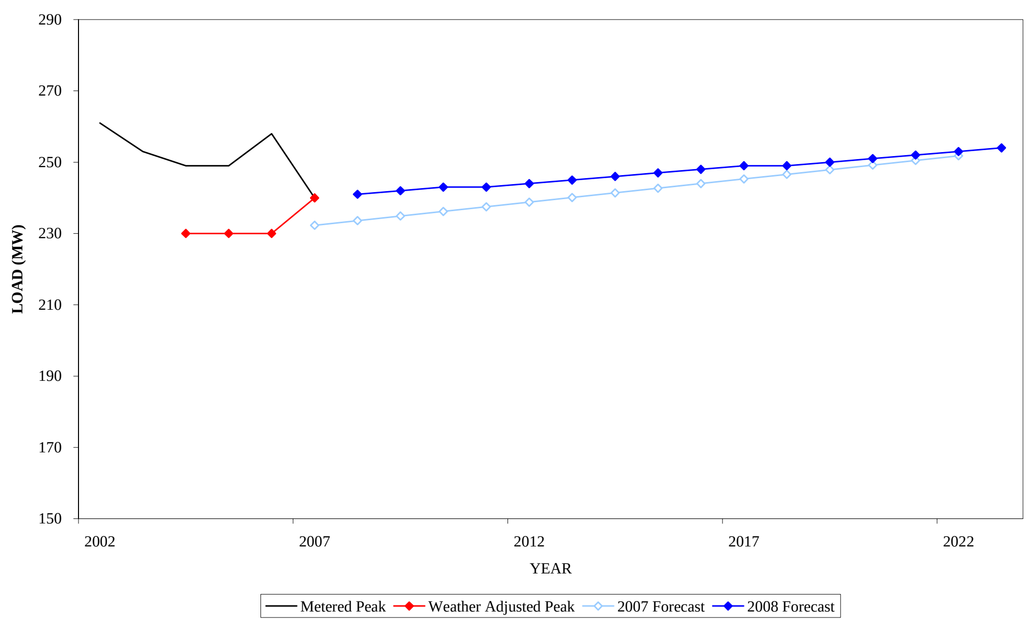
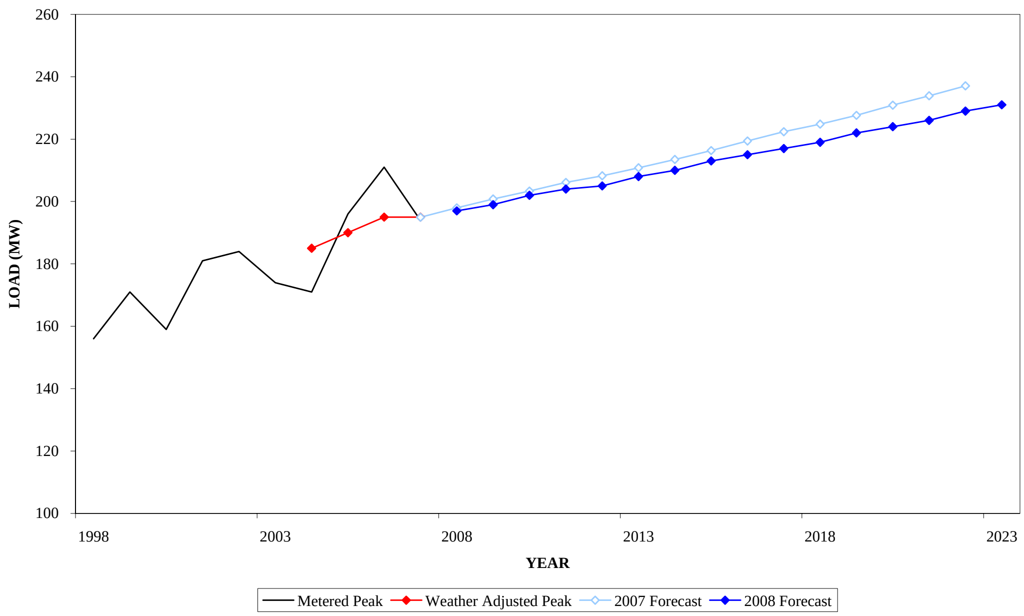
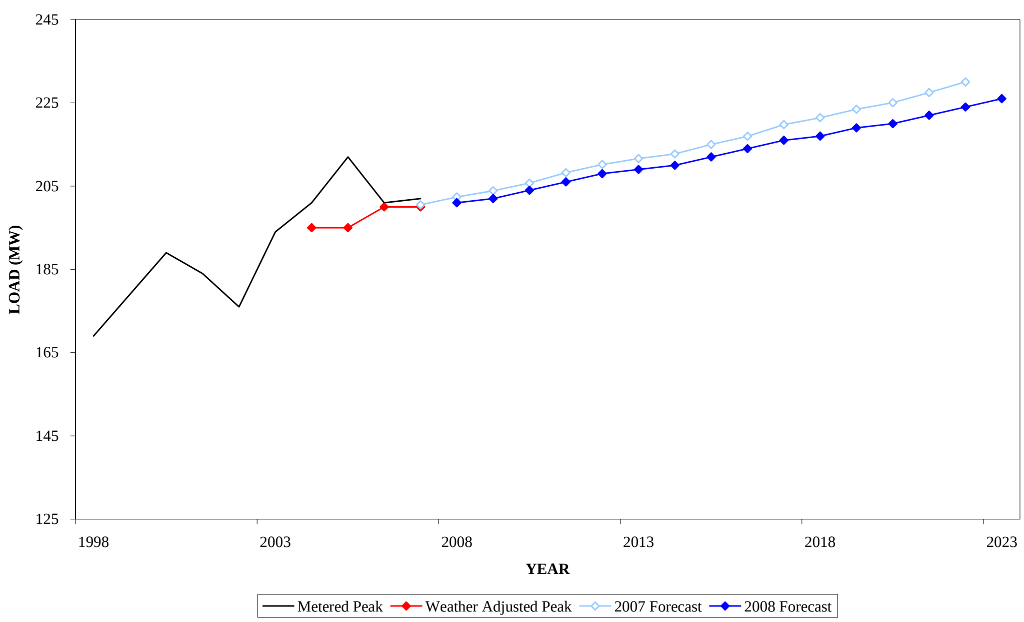


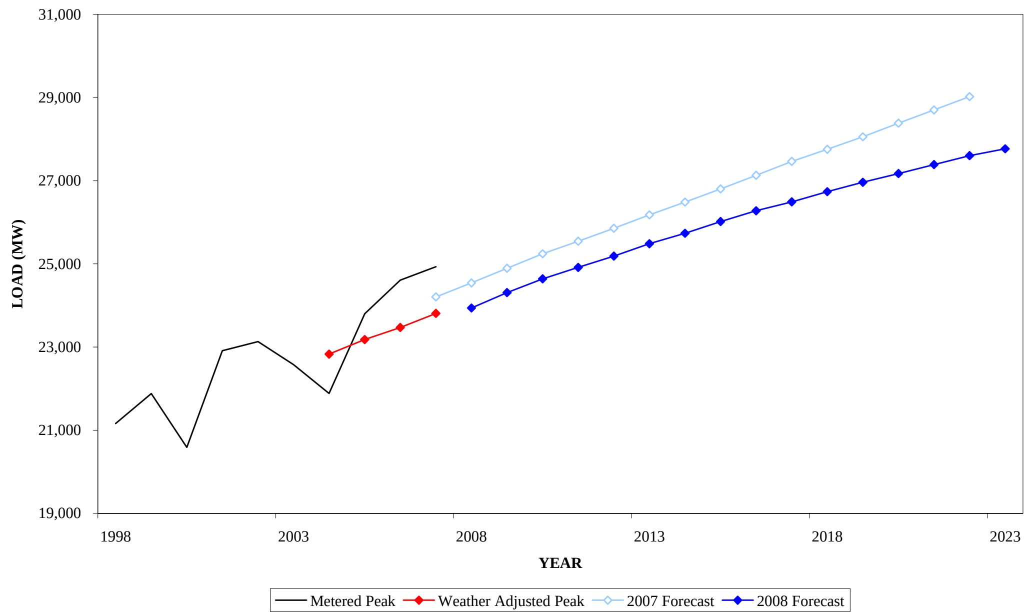
SUMMER PEAK DEMAND FOR UGI GEOGRAPHIC ZONE



WINTER PEAK DEMAND FOR UGI GEOGRAPHIC ZONE



SUMMER PEAK DEMAND FOR AEP GEOGRAPHIC ZONE



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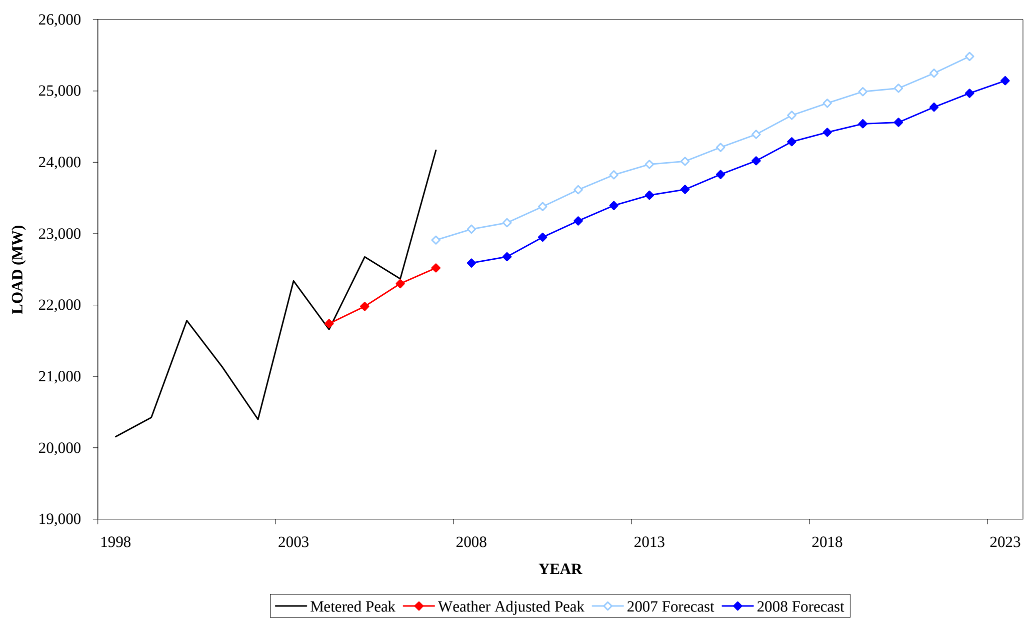

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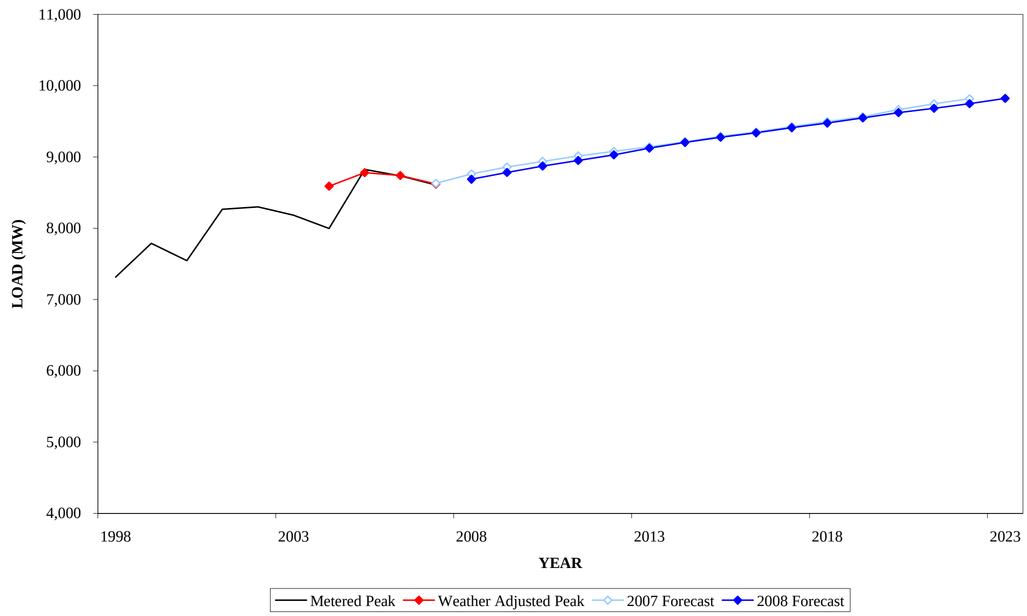

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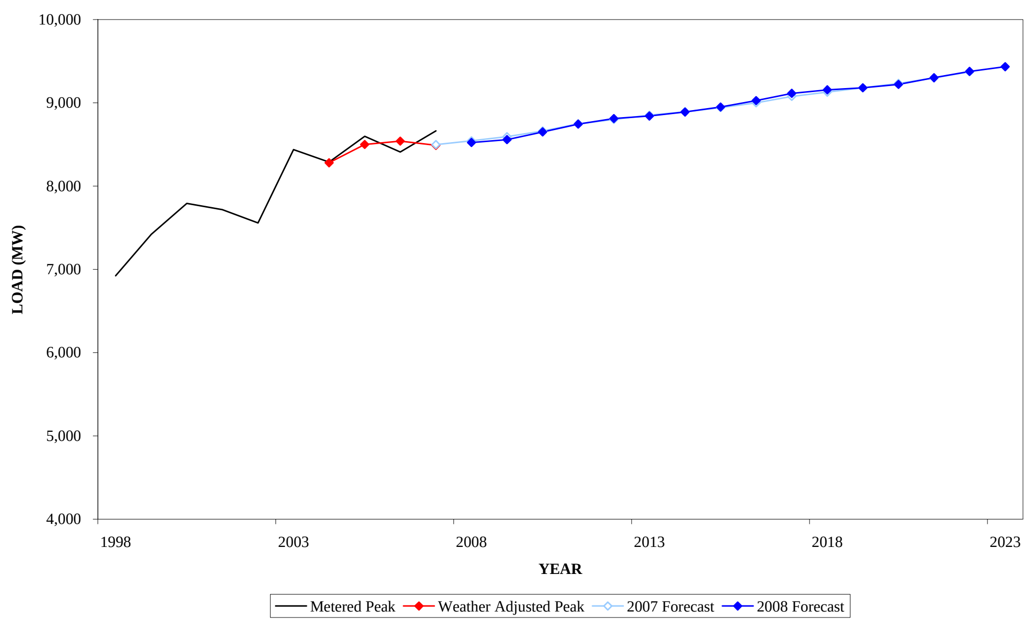
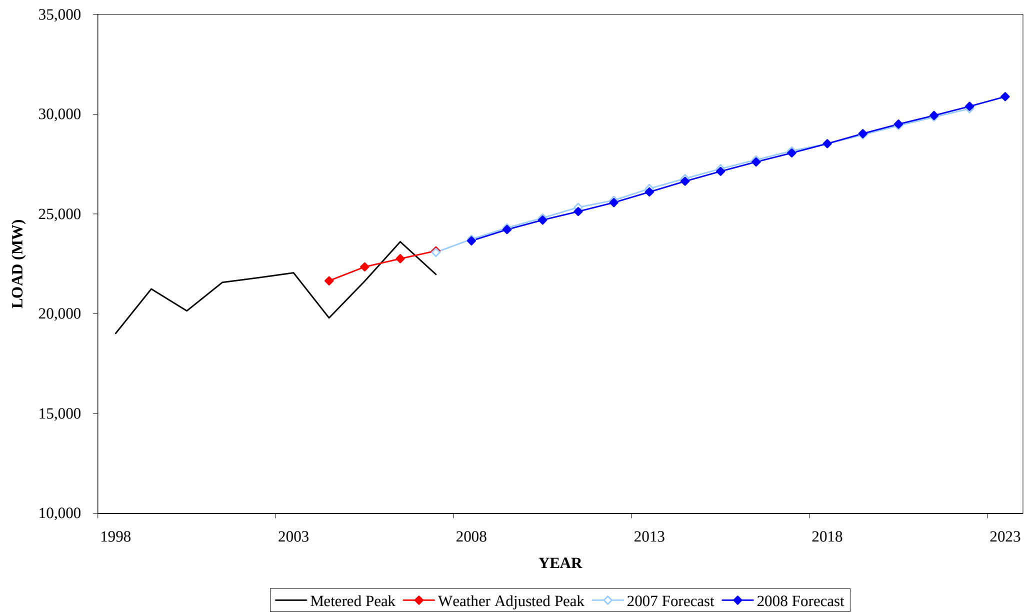


SUMMER PEAK DEMAND FOR COMED GEOGRAPHIC ZONE



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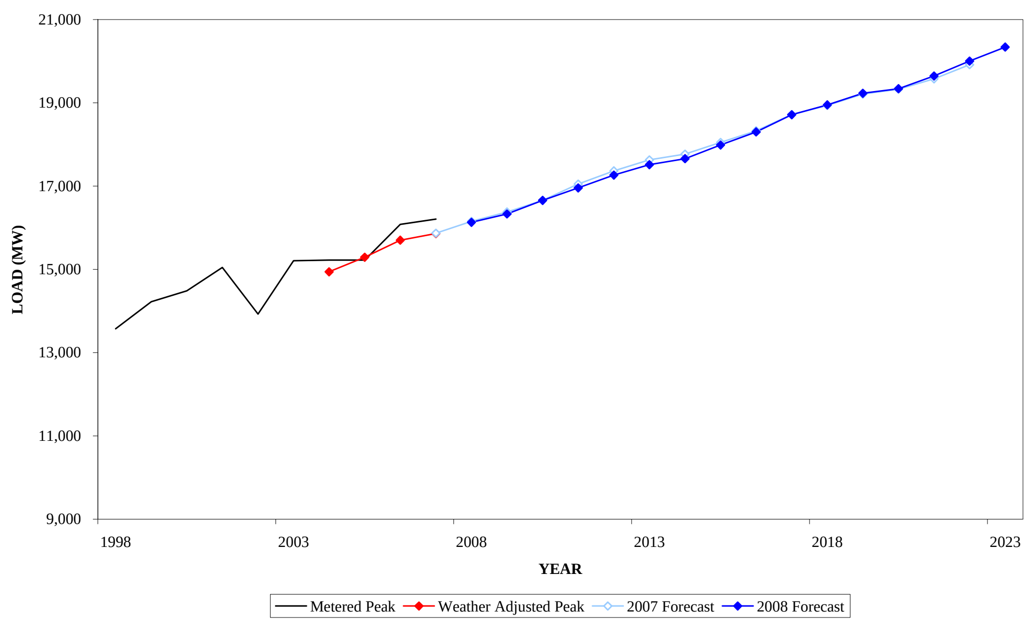
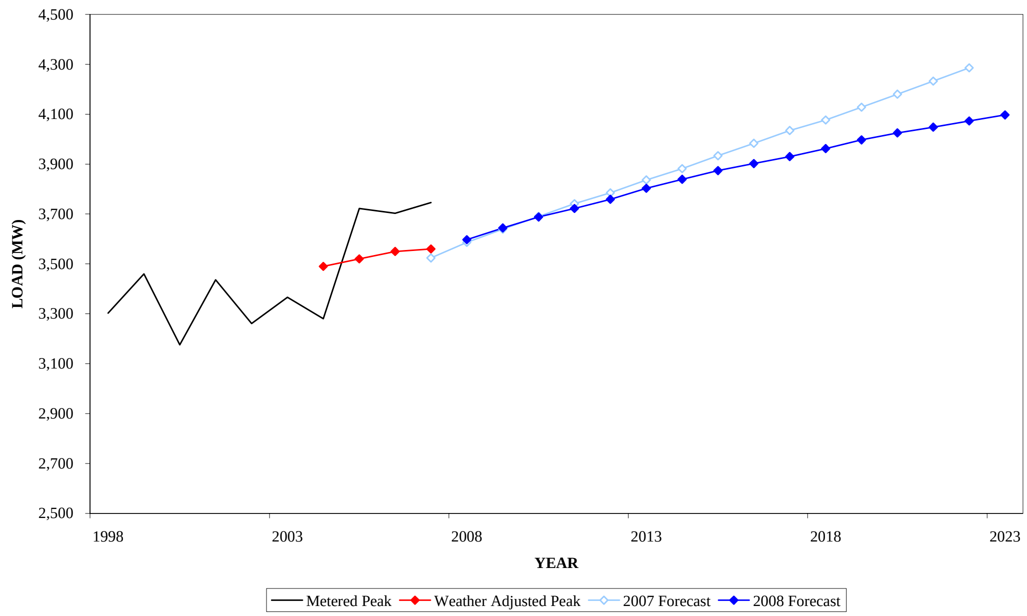
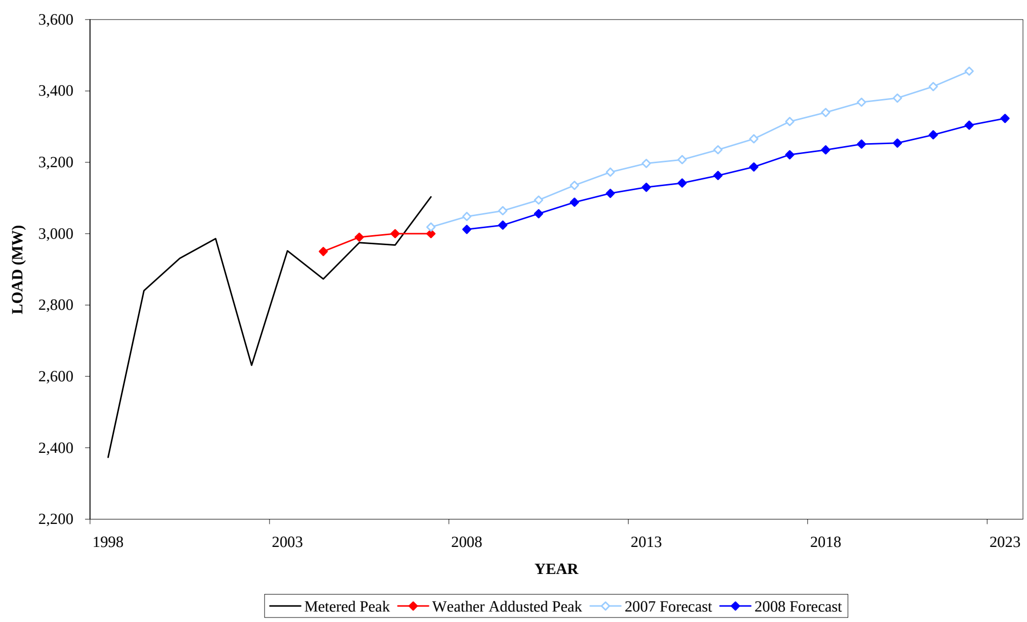


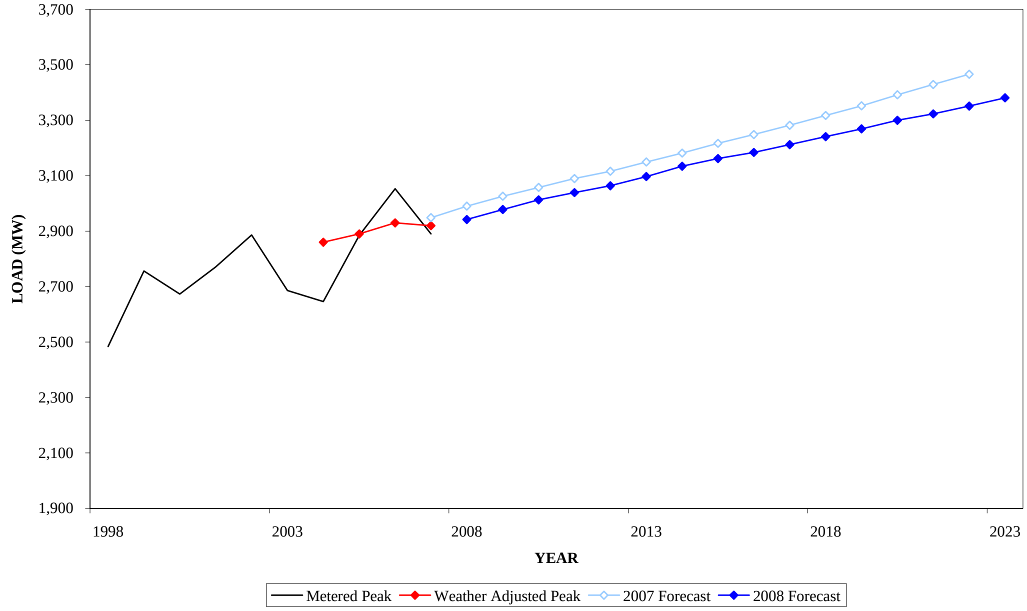
SUMMER PEAK DEMAND FOR DAY
GEOGRAPHIC ZONE



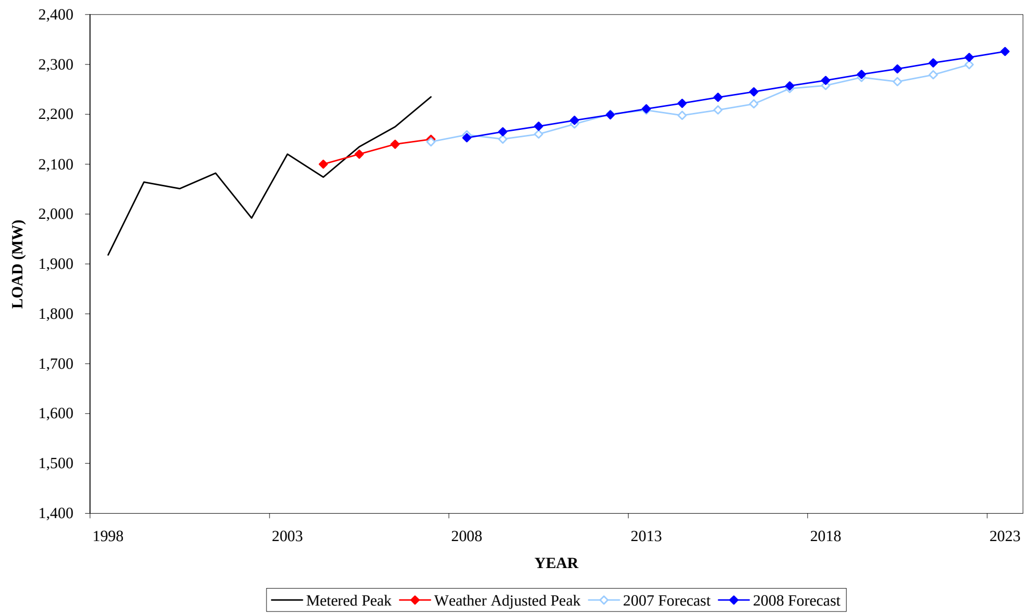
WINTER PEAK DEMAND FOR DAY
GEOGRAPHIC ZONE



**SUMMER PEAK DEMAND FOR DLCO
GEOGRAPHIC ZONE**



**WINTER PEAK DEMAND FOR DLCO
GEOGRAPHIC ZONE**



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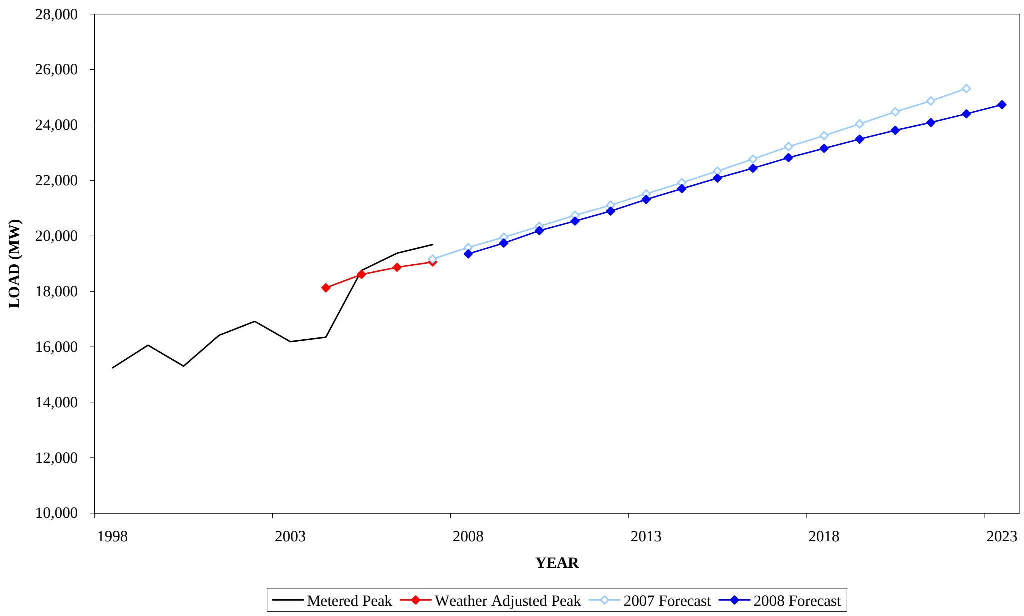
GEOGRAPHIC ZONE**



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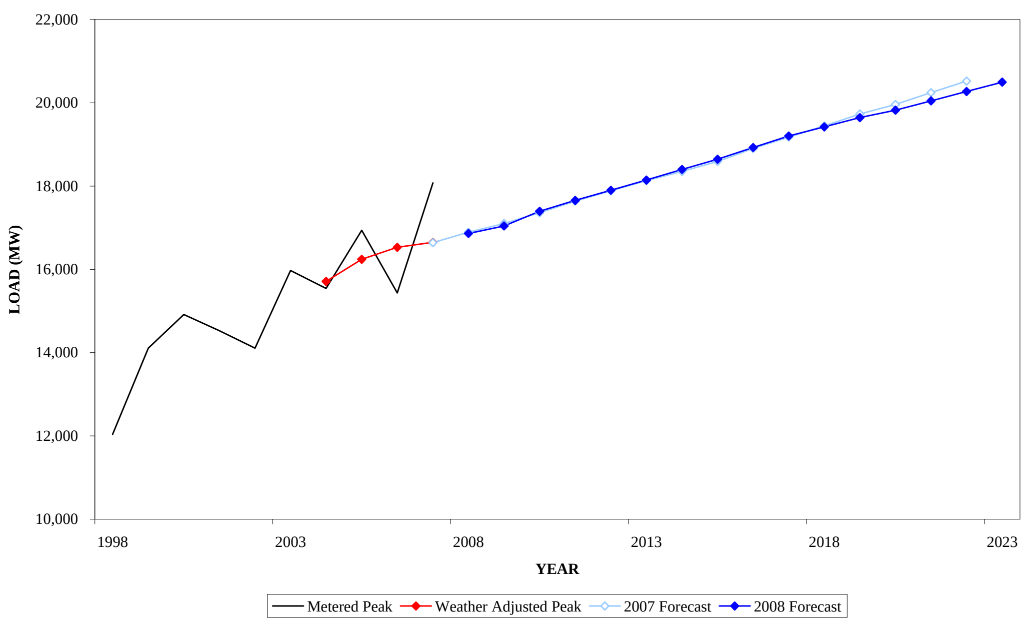
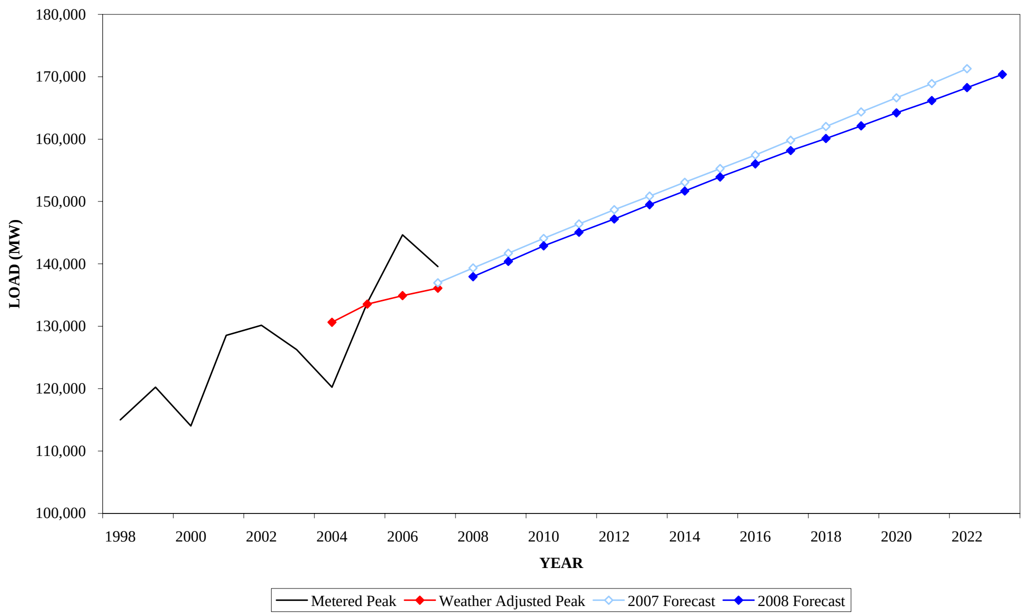


SUMMER PEAK DEMAND FOR PJM RTO



WINTER PEAK DEMAND FOR PJM RTO

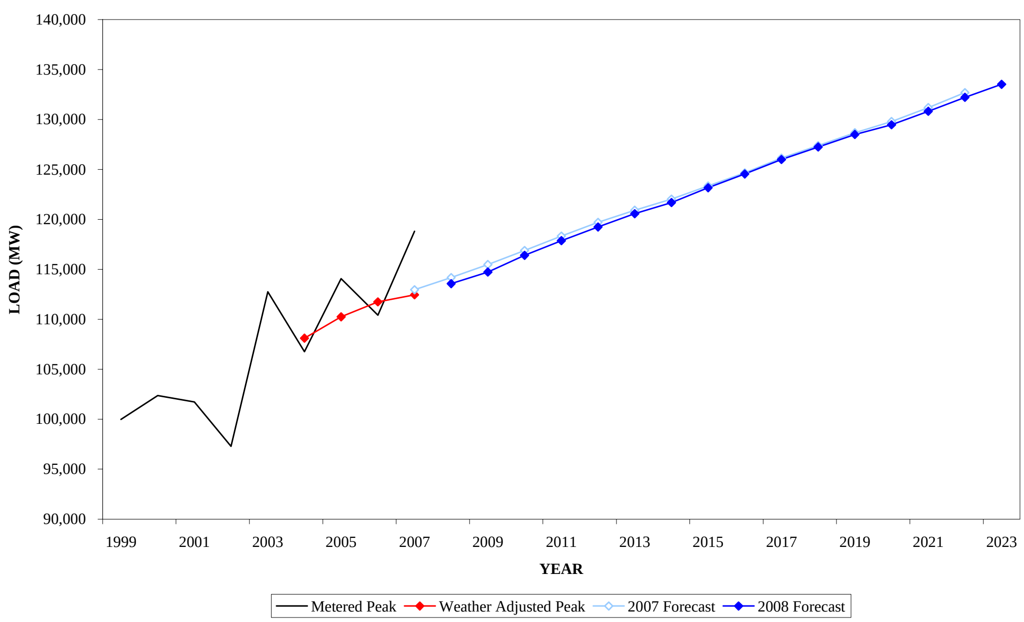


Table A-1

PJM MID-ATLANTIC
SUMMER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST
TO THE JANUARY 2007 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	2008		**2013**		**2017**	
	MW	**%**	**MW**	**%**	**MW**	**%**
AE	6	0.2%	227	7.3%	249	7.4%
BGE	(81)	-1.1%	(112)	-1.4%	(144)	-1.8%
DPL	26	0.6%	40	0.9%	51	1.0%
JCPL	11	0.2%	69	1.0%	85	1.1%
METED	21	0.7%	32	1.0%	38	1.1%
PECO	70	0.8%	135	1.5%	108	1.1%
PENLC	(23)	-0.8%	(65)	-2.1%	(112)	-3.5%
PEPCO	(69)	-1.0%	(100)	-1.3%	(93)	-1.2%
PL	(25)	-0.3%	(27)	-0.3%	(58)	-0.7%
PS	(10)	-0.1%	23	0.2%	19	0.2%
RECO	9	2.1%	24	5.5%	35	7.7%
UGI	(1)	-0.5%	(3)	-1.3%	(5)	-2.4%
PJM MID-ATLANTIC	(84)	-0.1%	223	0.3%	152	0.2%
FE/GPU	(31)	-0.3%	(9)	-0.1%	(36)	-0.3%
PLGRP	(26)	-0.3%	(29)	-0.4%	(63)	-0.7%

Table A-1

PJM WESTERN, PJM SOUTHERN AND PJM RTO
SUMMER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST
TO THE JANUARY 2007 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	2008		2013		2017	
	MW	%	MW	%	MW	%
AEP	(603)	-2.5%	(694)	-2.7%	(974)	-3.5%
APS	(74)	-0.8%	(18)	-0.2%	(17)	-0.2%
COMED	(84)	-0.4%	(168)	-0.6%	(102)	-0.4%
DAY	11	0.3%	(33)	-0.9%	(105)	-2.6%
DLCO	(48)	-1.6%	(52)	-1.7%	(70)	-2.1%
PJM WESTERN	(677)	-1.1%	(833)	-1.2%	(1122)	-1.6%
DOM	(230)	-1.2%	(204)	-0.9%	(398)	-1.7%
PJM RTO	(1394)	-1.0%	(1371)	-0.9%	(1646)	-1.0%

Table A-2

PJM MID-ATLANTIC
WINTER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST
TO THE JANUARY 2007 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	07/08		12/13		16/17	
	MW	**%**	**MW**	**%**	**MW**	**%**
AE	10	0.5%	137	7.0%	213	10.3%
BGE	(66)	-1.1%	(99)	-1.6%	(108)	-1.7%
DPL	(10)	-0.3%	(15)	-0.4%	(6)	-0.1%
JCPL	(19)	-0.5%	(1)	0.0%	11	0.2%
METED	(8)	-0.3%	(16)	-0.6%	(11)	-0.4%
PECO	(3)	0.0%	40	0.6%	57	0.8%
PENLC	(14)	-0.5%	(46)	-1.5%	(72)	-2.3%
PEPCO	(65)	-1.2%	(109)	-1.9%	(93)	-1.5%
PL	10	0.1%	37	0.5%	78	1.0%
PS	(63)	-0.9%	(58)	-0.8%	(45)	-0.6%
RECO	7	3.2%	5	2.0%	4	1.5%
UGI	(1)	-0.7%	(3)	-1.2%	(4)	-1.7%
PJM MID-ATLANTIC	(243)	-0.5%	(144)	-0.3%	(41)	-0.1%
FE/GPU	(44)	-0.5%	(59)	-0.6%	(67)	-0.6%
PLGRP	9	0.1%	35	0.5%	75	0.9%

Table A-2

PJM WESTERN, PJM SOUTHERN AND PJM RTO
WINTER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST
TO THE JANUARY 2007 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	07/08		12/13		16/17	
	MW	%	MW	%	MW	%
AEP	(476)	-2.1%	(432)	-1.8%	(371)	-1.5%
APS	(21)	-0.2%	(11)	-0.1%	37	0.4%
COMED	(22)	-0.1%	(115)	-0.7%	(4)	0.0%
DAY	(36)	-1.2%	(67)	-2.1%	(93)	-2.8%
DLCO	(6)	-0.3%	3	0.1%	5	0.2%
PJM WESTERN	(439)	-0.9%	(429)	-0.8%	(384)	-0.7%
DOM	(29)	-0.2%	14	0.1%	26	0.1%
PJM RTO	(613)	-0.5%	(347)	-0.3%	(139)	-0.1%

PJM CONTROL AREA - JANUARY 2008
UNRESTRICTED PEAK FORECAST: SUMMER/WINTER
2008-2018

SUMMER UNRESTRICTED PEAK (MW)

		2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**Annual Growth Rate (10 yr)**
PJM MID-ATLANTIC		60,735	61,822	62,885	63,920	64,748	65,850	66,818	67,741	68,679	69,599	70,472	1.5%
	%		1.8%	1.7%	1.6%	1.3%	1.7%	1.5%	1.4%	1.4%	1.3%	1.3%	
PJM WESTERN		61,407	62,497	63,446	64,272	65,114	66,090	67,010	67,901	68,727	69,500	70,320	1.4%
	%		1.8%	1.5%	1.3%	1.3%	1.5%	1.4%	1.3%	1.2%	1.1%	1.2%	
PJM SOUTHERN		19,353	19,743	20,192	20,538	20,895	21,315	21,704	22,084	22,441	22,824	23,157	1.8%
	%		2.0%	2.3%	1.7%	1.7%	2.0%	1.8%	1.8%	1.6%	1.7%	1.5%	
PJM RTO		137,948	140,407	142,884	145,061	147,183	149,495	151,675	153,933	156,030	158,176	160,107	1.5%
	%		1.8%	1.8%	1.5%	1.5%	1.6%	1.5%	1.5%	1.4%	1.4%	1.2%	

WINTER UNRESTRICTED PEAK (MW)

		07/08	**08/09**	**09/010**	**010/11**	**11/12**	**12/13**	**13/14**	**14/15**	**15/16**	**16/17**	**17/18**	**Annual Growth Rate (10 yr)**
PJM MID-ATLANTIC		46,651	47,101	47,778	48,413	48,997	49,529	50,023	50,582	51,155	51,776	52,310	1.2%
	%		1.0%	1.4%	1.3%	1.2%	1.1%	1.0%	1.1%	1.1%	1.2%	1.0%	
PJM WESTERN		51,105	51,511	52,193	52,808	53,360	53,816	54,240	54,786	55,368	56,070	56,519	1.0%
	%		0.8%	1.3%	1.2%	1.0%	0.9%	0.8%	1.0%	1.1%	1.3%	0.8%	
PJM SOUTHERN		16,861	17,043	17,395	17,657	17,900	18,146	18,399	18,646	18,927	19,203	19,422	1.4%
	%		1.1%	2.1%	1.5%	1.4%	1.4%	1.4%	1.3%	1.5%	1.5%	1.1%	
PJM RTO		113,565	114,728	116,408	117,871	119,240	120,569	121,685	123,165	124,545	125,996	127,250	1.1%
	%		1.0%	1.5%	1.3%	1.2%	1.1%	0.9%	1.2%	1.1%	1.2%	1.0%	

Note:
Projected PJM seasonal peak load under normal peak weather conditions in the absense of any load reductions due to active load management, voltage reductions or voluntary curtailments.

PJM CONTROL AREA - JANUARY 2008
UNRESTRICTED PEAK FORECAST: SUMMER/WINTER
2019-2023

SUMMER UNRESTRICTED PEAK (MW)

		2019	2020	2021	2022	2023	Annual Growth Rate (15 yr)
PJM MID-ATLANTIC		71,478	72,425	73,358	74,374	75,367	1.4%
	%	1.4%	1.3%	1.3%	1.4%	1.3%	
PJM WESTERN		71,162	71,964	72,705	73,472	74,238	1.3%
	%	1.2%	1.1%	1.0%	1.1%	1.0%	
PJM SOUTHERN		23,489	23,813	24,089	24,403	24,731	1.6%
	%	1.4%	1.4%	1.2%	1.3%	1.3%	
PJM RTO		162,132	164,209	166,179	168,258	170,367	1.4%
	%	1.3%	1.3%	1.2%	1.3%	1.3%	

WINTER UNRESTRICTED PEAK (MW)

		18/19	19/20	20/21	21/22	22/23	Annual Growth Rate (15 yr)
PJM MID-ATLANTIC		52,835	53,255	53,884	54,536	55,114	1.1%
	%	1.0%	0.8%	1.2%	1.2%	1.1%	
PJM WESTERN		56,907	57,214	57,781	58,395	58,897	1.0%
	%	0.7%	0.5%	1.0%	1.1%	0.9%	
PJM SOUTHERN		19,645	19,824	20,047	20,273	20,498	1.3%
	%	1.1%	0.9%	1.1%	1.1%	1.1%	
PJM RTO		128,497	129,475	130,819	132,219	133,518	1.1%
	%	1.0%	0.8%	1.0%	1.1%	1.0%	

Note:
Projected PJM seasonal peak load under normal peak weather conditions in the absense of any load reductions due to active load management, voltage reductions or voluntary curtailments.

Table B-1

SUMMER PEAK LOAD (MW) AND GROWTH RATES FOR
EACH PJM MID-ATLANTIC GEOGRAPHIC ZONE AND SUM OF GEOGRAPHIC ZONES
2008-2018

		METERED 2007	UNRESTRICTED 2007	NORMAL 2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Annual Growth Rate (10 yr)
AE		2,971	3,020	2,760	2,829	2,897	2,975	3,155	3,221	3,358	3,440	3,498	3,571	3,622	3,673	2.6%
	%				2.5%	2.4%	2.7%	6.1%	2.1%	4.3%	2.4%	1.7%	2.1%	1.4%	1.4%	
BGE		7,113	7,477	7,260	7,344	7,455	7,555	7,626	7,693	7,783	7,858	7,930	7,981	8,054	8,118	1.0%
	%				1.2%	1.5%	1.3%	0.9%	0.9%	1.2%	1.0%	0.9%	0.6%	0.9%	0.8%	
DPL		4,265	4,422	4,130	4,192	4,278	4,360	4,442	4,522	4,617	4,699	4,781	4,874	4,970	5,047	1.9%
	%				1.5%	2.1%	1.9%	1.9%	1.8%	2.1%	1.8%	1.7%	1.9%	2.0%	1.5%	
JCPL		6,152	6,313	6,370	6,478	6,636	6,804	6,947	7,061	7,205	7,346	7,485	7,637	7,773	7,897	2.0%
	%				1.7%	2.4%	2.5%	2.1%	1.6%	2.0%	2.0%	1.9%	2.0%	1.8%	1.6%	
METED		2,934	2,995	2,890	2,929	2,982	3,044	3,094	3,132	3,186	3,234	3,284	3,339	3,387	3,432	1.6%
	%				1.3%	1.8%	2.1%	1.6%	1.2%	1.7%	1.5%	1.5%	1.7%	1.4%	1.3%	
PECO		8,549	8,851	8,630	8,759	8,909	9,055	9,183	9,309	9,447	9,577	9,702	9,826	9,955	10,085	1.4%
	%				1.5%	1.7%	1.6%	1.4%	1.4%	1.5%	1.4%	1.3%	1.3%	1.3%	1.3%	
PENLC		2,881	2,901	2,820	2,850	2,892	2,930	2,963	2,985	3,023	3,054	3,082	3,111	3,136	3,157	1.0%
	%				1.1%	1.5%	1.3%	1.1%	0.7%	1.3%	1.0%	0.9%	0.9%	0.8%	0.7%	
PEPCO		6,858	6,892	6,950	7,057	7,159	7,252	7,335	7,424	7,541	7,645	7,744	7,838	7,939	8,046	1.3%
	%				1.5%	1.4%	1.3%	1.1%	1.2%	1.6%	1.4%	1.3%	1.2%	1.3%	1.3%	
PL		7,141	7,304	7,200	7,292	7,420	7,536	7,643	7,731	7,853	7,951	8,061	8,172	8,275	8,379	1.4%
	%				1.3%	1.8%	1.6%	1.4%	1.2%	1.6%	1.2%	1.4%	1.4%	1.3%	1.3%	
PS		10,239	10,475	10,820	10,967	11,158	11,340	11,501	11,642	11,812	11,990	12,151	12,309	12,470	12,622	1.4%
	%				1.4%	1.7%	1.6%	1.4%	1.2%	1.5%	1.5%	1.3%	1.3%	1.3%	1.2%	
RECO		423	423	430	435	441	447	452	456	461	467	472	477	481	486	1.1%
	%				1.2%	1.4%	1.4%	1.1%	0.9%	1.1%	1.3%	1.1%	1.1%	0.8%	1.0%	
UGI		194	194	195	197	199	202	204	205	208	210	213	215	217	219	1.1%
	%				1.0%	1.0%	1.5%	1.0%	0.5%	1.5%	1.0%	1.4%	0.9%	0.9%	0.9%	
DIVERSITY (-)					594	604	615	625	633	644	653	662	671	680	689	
PJM MID-ATLANTIC		59,553	61,192		60,735	61,822	62,885	63,920	64,748	65,850	66,818	67,741	68,679	69,599	70,472	1.5%
	%					1.8%	1.7%	1.6%	1.3%	1.7%	1.5%	1.4%	1.4%	1.3%	1.3%	
FE/GPU		11,685	12,209	11,911	12,086	12,335	12,599	12,822	12,994	13,226	13,443	13,657	13,890	14,096	14,283	1.7%
	%				1.5%	2.1%	2.1%	1.8%	1.3%	1.8%	1.6%	1.6%	1.7%	1.5%	1.3%	
PLGRP		7,230	7,497	7,392	7,486	7,616	7,735	7,844	7,932	8,057	8,157	8,270	8,383	8,488	8,594	1.4%
	%				1.3%	1.7%	1.6%	1.4%	1.1%	1.6%	1.2%	1.4%	1.4%	1.3%	1.2%	

Note:
Normal 2007 and all forecast values are non-coincident as estimated by PJM staff.
Normal 2007 and all forecast values represent unrestricted peaks.
Forecasted and weather-normalized values for FE/GPU and PLGRP are calculated as the diversified sum of zonal non-coincident values.

Table B-1 (Continued)

SUMMER PEAK LOAD (MW) AND GROWTH RATES FOR
EACH PJM MID-ATLANTIC GEOGRAPHIC ZONE AND SUM OF GEOGRAPHIC ZONES
2019-2023

		2019	2020	2021	2022	2023	Annual Growth Rate (15 yr)
AE		3,733	3,790	3,852	3,918	3,976	2.3%
	%	1.6%	1.5%	1.6%	1.7%	1.5%	
BGE		8,204	8,276	8,335	8,404	8,480	1.0%
	%	1.1%	0.9%	0.7%	0.8%	0.9%	
DPL		5,150	5,236	5,335	5,440	5,544	1.9%
	%	2.0%	1.7%	1.9%	2.0%	1.9%	
JCPL		8,035	8,173	8,322	8,474	8,622	1.9%
	%	1.7%	1.7%	1.8%	1.8%	1.7%	
METED		3,490	3,546	3,601	3,661	3,715	1.6%
	%	1.7%	1.6%	1.6%	1.7%	1.5%	
PECO		10,213	10,334	10,460	10,592	10,729	1.4%
	%	1.3%	1.2%	1.2%	1.3%	1.3%	
PENLC		3,185	3,212	3,237	3,263	3,288	1.0%
	%	0.9%	0.8%	0.8%	0.8%	0.8%	
PEPCO		8,156	8,259	8,352	8,461	8,567	1.3%
	%	1.4%	1.3%	1.1%	1.3%	1.3%	
PL		8,506	8,626	8,735	8,859	8,975	1.4%
	%	1.5%	1.4%	1.3%	1.4%	1.3%	
PS		12,792	12,960	13,119	13,294	13,466	1.4%
	%	1.3%	1.3%	1.2%	1.3%	1.3%	
RECO		491	497	501	506	511	1.1%
	%	1.0%	1.2%	0.8%	1.0%	1.0%	
UGI		222	224	226	229	231	1.1%
	%	1.4%	0.9%	0.9%	1.3%	0.9%	
DIVERSITY (-)		699	708	717	727	737	
PJM MID-ATLANTIC		71,478	72,425	73,358	74,374	75,367	1.4%
	%	1.4%	1.3%	1.3%	1.4%	1.3%	
FE/GPU		14,504	14,722	14,948	15,183	15,406	1.6%
	%	1.5%	1.5%	1.5%	1.6%	1.5%	
PLGRP		8,724	8,846	8,957	9,084	9,202	1.4%
	%	1.5%	1.4%	1.3%	1.4%	1.3%	

Note:
Normal 2007 and all forecast values are non-coincident as estimated by PJM staff.
Normal 2007 and all forecast values represent unrestricted peaks.
Forecasted and weather-normalized values for FE/GPU and PLGRP are calculated as the diversified sum of zonal non-coincident values.

Table B-1

SUMMER PEAK LOAD (MW) AND GROWTH RATES FOR
EACH PJM WESTERN AND PJM SOUTHERN GEOGRAPHIC ZONE AND SUM OF GEOGRAPHIC ZONES
2008-2018

		METERED 2007	UNRESTRICTED 2007	NORMAL 2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Annual Growth Rate (10 yr)
AEP		24,934	25,301	23,810	23,939	24,311	24,640	24,915	25,188	25,485	25,737	26,017	26,277	26,490	26,736	1.1%
	%				0.5%	1.6%	1.4%	1.1%	1.1%	1.2%	1.0%	1.1%	1.0%	0.8%	0.9%	
APS		8,607	8,638	8,620	8,688	8,783	8,872	8,951	9,030	9,124	9,203	9,276	9,338	9,410	9,475	0.9%
	%				0.8%	1.1%	1.0%	0.9%	0.9%	1.0%	0.9%	0.8%	0.7%	0.8%	0.7%	
COMED		21,972	21,972	23,150	23,654	24,219	24,693	25,124	25,571	26,102	26,639	27,135	27,608	28,057	28,524	1.9%
	%				2.2%	2.4%	2.0%	1.7%	1.8%	2.1%	2.1%	1.9%	1.7%	1.6%	1.7%	
DAY		3,746	3,748	3,560	3,597	3,644	3,688	3,722	3,759	3,803	3,839	3,874	3,902	3,930	3,962	1.0%
	%				1.0%	1.3%	1.2%	0.9%	1.0%	1.2%	0.9%	0.9%	0.7%	0.7%	0.8%	
DLCO		2,890	2,890	2,920	2,942	2,978	3,013	3,039	3,064	3,097	3,134	3,162	3,184	3,212	3,241	1.0%
	%				0.8%	1.2%	1.2%	0.9%	0.8%	1.1%	1.2%	0.9%	0.7%	0.9%	0.9%	
DIVERSITY (-)					1,413	1,438	1,460	1,479	1,498	1,521	1,542	1,563	1,582	1,599	1,618	
PJM WESTERN		60,435	60,835		61,407	62,497	63,446	64,272	65,114	66,090	67,010	67,901	68,727	69,500	70,320	1.4%
	%					1.8%	1.5%	1.3%	1.3%	1.5%	1.4%	1.3%	1.2%	1.1%	1.2%	
DOM		19,688	20,083	19,060	19,353	19,743	20,192	20,538	20,895	21,315	21,704	22,084	22,441	22,824	23,157	1.8%
	%				1.5%	2.0%	2.3%	1.7%	1.7%	2.0%	1.8%	1.8%	1.6%	1.7%	1.5%	
DIVERSITY (-)					3,547	3,655	3,639	3,669	3,574	3,760	3,857	3,793	3,817	3,747	3,842	
PJM RTO		139,568	141,383	136,095	137,948	140,407	142,884	145,061	147,183	149,495	151,675	153,933	156,030	158,176	160,107	1.5%
	%				1.4%	1.8%	1.8%	1.5%	1.5%	1.6%	1.5%	1.5%	1.4%	1.4%	1.2%	

Note:
Normal 2007 and all forecast values are non-coincident as estimated by PJM staff.
Normal 2007 and all forecast values represent unrestricted peaks.

Table B-1 (Continued)

SUMMER PEAK LOAD (MW) AND GROWTH RATES FOR
EACH PJM WESTERN AND PJM SOUTHERN GEOGRAPHIC ZONE AND SUM OF GEOGRAPHIC ZONES
2019-2023

		2019	2020	2021	2022	2023	Annual Growth Rate (15 yr)
AEP		26,961	27,171	27,389	27,602	27,768	1.0%
	%	0.8%	0.8%	0.8%	0.8%	0.6%	
APS		9,548	9,622	9,682	9,747	9,822	0.8%
	%	0.8%	0.8%	0.6%	0.7%	0.8%	
COMED		29,025	29,502	29,936	30,390	30,878	1.8%
	%	1.8%	1.6%	1.5%	1.5%	1.6%	
DAY		3,997	4,025	4,048	4,073	4,097	0.9%
	%	0.9%	0.7%	0.6%	0.6%	0.6%	
DLCO		3,269	3,300	3,323	3,351	3,381	0.9%
	%	0.9%	0.9%	0.7%	0.8%	0.9%	
DIVERSITY (-)		1,638	1,656	1,673	1,691	1,708	
PJM WESTERN		71,162	71,964	72,705	73,472	74,238	1.3%
	%	1.2%	1.1%	1.0%	1.1%	1.0%	
DOM		23,489	23,813	24,089	24,403	24,731	1.6%
	%	1.4%	1.4%	1.2%	1.3%	1.3%	
DIVERSITY (-)		3,997	3,993	3,973	3,991	3,969	
PJM RTO		162,132	164,209	166,179	168,258	170,367	1.4%
	%	1.3%	1.3%	1.2%	1.3%	1.3%	

Note:
Normal 2007 and all forecast values are non-coincident as estimated by PJM staff.
Normal 2007 and all forecast values represent unrestricted peaks.

Table B-2

WINTER PEAK LOAD (MW) AND GROWTH RATES FOR
EACH PJM MID-ATLANTIC GEOGRAPHIC ZONE AND SUM OF GEOGRAPHIC ZONES
2007/08-2017/18

		METERED 06/07	UNRESTRICTED 06/07	NORMAL 06/07	07/08	08/09	09/010	010/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	Annual Growth Rate (10 yr)
AE		1,792	1,792	1,810	1,846	1,880	1,925	1,964	2,062	2,105	2,172	2,211	2,245	2,285	2,314	2.3%
	%				2.0%	1.8%	2.4%	2.0%	5.0%	2.1%	3.2%	1.8%	1.5%	1.8%	1.3%	
BGE		6,347	6,347	5,980	6,009	6,047	6,105	6,156	6,191	6,222	6,254	6,287	6,329	6,367	6,400	0.6%
	%				0.5%	0.6%	1.0%	0.8%	0.6%	0.5%	0.5%	0.5%	0.7%	0.6%	0.5%	
DPL		3,603	3,603	3,360	3,397	3,442	3,497	3,547	3,598	3,642	3,685	3,743	3,798	3,857	3,908	1.4%
	%				1.1%	1.3%	1.6%	1.4%	1.4%	1.2%	1.2%	1.6%	1.5%	1.6%	1.3%	
JCPL		4,075	4,075	3,970	4,013	4,066	4,152	4,227	4,300	4,357	4,404	4,482	4,560	4,638	4,699	1.6%
	%				1.1%	1.3%	2.1%	1.8%	1.7%	1.3%	1.1%	1.8%	1.7%	1.7%	1.3%	
METED		2,624	2,624	2,540	2,575	2,596	2,634	2,677	2,710	2,740	2,767	2,799	2,832	2,874	2,906	1.2%
	%				1.4%	0.8%	1.5%	1.6%	1.2%	1.1%	1.0%	1.2%	1.2%	1.5%	1.1%	
PECO		6,835	6,835	6,530	6,602	6,682	6,780	6,880	6,960	7,037	7,104	7,189	7,277	7,377	7,449	1.2%
	%				1.1%	1.2%	1.5%	1.5%	1.2%	1.1%	1.0%	1.2%	1.2%	1.4%	1.0%	
PENLC		2,895	2,895	2,790	2,820	2,835	2,874	2,914	2,945	2,972	2,987	3,014	3,042	3,081	3,100	1.0%
	%				1.1%	0.5%	1.4%	1.4%	1.1%	0.9%	0.5%	0.9%	0.9%	1.3%	0.6%	
PEPCO		5,606	5,606	5,320	5,381	5,432	5,501	5,568	5,629	5,681	5,750	5,807	5,881	5,955	6,019	1.1%
	%				1.1%	0.9%	1.3%	1.2%	1.1%	0.9%	1.2%	1.0%	1.3%	1.3%	1.1%	
PL		7,577	7,577	7,160	7,232	7,281	7,374	7,451	7,520	7,579	7,633	7,704	7,780	7,871	7,939	0.9%
	%				1.0%	0.7%	1.3%	1.0%	0.9%	0.8%	0.7%	0.9%	1.0%	1.2%	0.9%	
PS		7,050	7,050	7,000	7,070	7,137	7,249	7,360	7,465	7,538	7,599	7,699	7,798	7,922	7,996	1.2%
	%				1.0%	0.9%	1.6%	1.5%	1.4%	1.0%	0.8%	1.3%	1.3%	1.6%	0.9%	
RECO		240	240	240	241	242	243	243	244	245	246	247	248	249	249	0.3%
	%				0.4%	0.4%	0.4%	0.0%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.0%	
UGI		202	202	200	201	202	204	206	208	209	210	212	214	216	217	0.8%
	%				0.5%	0.5%	1.0%	1.0%	1.0%	0.5%	0.5%	1.0%	0.9%	0.9%	0.5%	
DIVERSITY (-)					736	741	760	780	835	798	788	812	849	916	886	
PJM MID-ATLANTIC		48,543	48,543		46,651	47,101	47,778	48,413	48,997	49,529	50,023	50,582	51,155	51,776	52,310	1.2%
	%					1.0%	1.4%	1.3%	1.2%	1.1%	1.0%	1.1%	1.1%	1.2%	1.0%	
FE/GPU		9,273	9,298	9,231	9,335	9,427	9,587	9,734	9,863	9,985	10,083	10,219	10,342	10,481	10,601	1.3%
	%				1.1%	1.0%	1.7%	1.5%	1.3%	1.2%	1.0%	1.3%	1.2%	1.3%	1.1%	
PLGRP		7,280	7,280	7,356	7,429	7,479	7,574	7,653	7,724	7,784	7,839	7,912	7,990	8,083	8,152	0.9%
	%				1.0%	0.7%	1.3%	1.0%	0.9%	0.8%	0.7%	0.9%	1.0%	1.2%	0.9%	

Note:
Normal 06/07 and all forecast values are non-coincident as estimated by PJM staff.
Normal 06/07 and all forecast values represent unrestricted peaks.
Forecasted values for PLGRP and FE/GPU are calculated as the diversified sum of zonal non-coincident forecasts.

Table B-2 (Continued)

**WINTER PEAK LOAD (MW) AND GROWTH RATES FOR
EACH PJM MID-ATLANTIC GEOGRAPHIC ZONE AND SUM OF GEOGRAPHIC ZONES
2018/19-2022/23**

		18/19	19/20	20/21	21/22	22/23	Annual Growth Rate (15 yr)
AE		2,349	2,366	2,405	2,444	2,485	2.0%
	%	1.5%	0.7%	1.6%	1.6%	1.7%	
BGE		6,432	6,456	6,498	6,544	6,578	0.6%
	%	0.5%	0.4%	0.7%	0.7%	0.5%	
DPL		3,958	4,005	4,075	4,139	4,202	1.4%
	%	1.3%	1.2%	1.7%	1.6%	1.5%	
JCPL		4,762	4,801	4,890	4,970	5,049	1.5%
	%	1.3%	0.8%	1.9%	1.6%	1.6%	
METED		2,942	2,968	3,007	3,051	3,090	1.2%
	%	1.2%	0.9%	1.3%	1.5%	1.3%	
PECO		7,529	7,585	7,682	7,780	7,865	1.2%
	%	1.1%	0.7%	1.3%	1.3%	1.1%	
PENLC		3,126	3,133	3,161	3,194	3,223	0.9%
	%	0.8%	0.2%	0.9%	1.0%	0.9%	
PEPCO		6,082	6,140	6,204	6,282	6,355	1.1%
	%	1.0%	1.0%	1.0%	1.3%	1.2%	
PL		8,008	8,059	8,148	8,240	8,320	0.9%
	%	0.9%	0.6%	1.1%	1.1%	1.0%	
PS		8,079	8,131	8,245	8,358	8,468	1.2%
	%	1.0%	0.6%	1.4%	1.4%	1.3%	
RECO		250	251	252	253	254	0.4%
	%	0.4%	0.4%	0.4%	0.4%	0.4%	
UGI		219	220	222	224	226	0.8%
	%	0.9%	0.5%	0.9%	0.9%	0.9%	
DIVERSITY (-)		901	860	905	943	1,001	
PJM MID-ATLANTIC		52,835	53,255	53,884	54,536	55,114	1.1%
	%	1.0%	0.8%	1.2%	1.2%	1.1%	
FE/GPU		10,727	10,821	10,959	11,103	11,239	1.2%
	%	1.2%	0.9%	1.3%	1.3%	1.2%	
PLGRP		8,223	8,275	8,366	8,460	8,542	0.9%
	%	0.9%	0.6%	1.1%	1.1%	1.0%	

Note:
Normal 06/07 and all forecast values are non-coincident as estimated by PJM staff.
Normal 06/07 and all forecast values represent unrestricted peaks.
Forecasted values for PLGRP and FE/GPU are calculated as the diversified sum of zonal non-coincident forecasts.

Table B-2

WINTER PEAK LOAD (MW) AND GROWTH RATES FOR
EACH PJM WESTERN AND PJM SOUTHERN GEOGRAPHIC ZONE AND SUM OF GEOGRAPHIC ZONES
2007/08-2017/18

		METERED 06/07	UNRESTRICTED 06/07	NORMAL 06/07	07/08	08/09	09/010	010/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	Annual Growth Rate (10 yr)
AEP		22,367	22,367	22,520	22,588	22,677	22,950	23,179	23,394	23,539	23,620	23,830	24,021	24,288	24,420	0.8%
	%				0.3%	0.4%	1.2%	1.0%	0.9%	0.6%	0.3%	0.9%	0.8%	1.1%	0.5%	
APS		8,410	8,410	8,490	8,523	8,558	8,651	8,744	8,811	8,841	8,890	8,950	9,027	9,114	9,156	0.7%
	%				0.4%	0.4%	1.1%	1.1%	0.8%	0.3%	0.6%	0.7%	0.9%	1.0%	0.5%	
COMED		16,081	16,081	15,860	16,129	16,331	16,657	16,955	17,263	17,514	17,659	17,987	18,301	18,715	18,952	1.6%
	%				1.7%	1.3%	2.0%	1.8%	1.8%	1.5%	0.8%	1.9%	1.7%	2.3%	1.3%	
DAY		2,968	2,968	3,000	3,012	3,024	3,056	3,088	3,113	3,130	3,142	3,163	3,187	3,221	3,235	0.7%
	%				0.4%	0.4%	1.1%	1.0%	0.8%	0.5%	0.4%	0.7%	0.8%	1.1%	0.4%	
DLCO		2,175	2,175	2,150	2,153	2,165	2,176	2,188	2,199	2,211	2,222	2,234	2,245	2,257	2,268	0.5%
	%				0.1%	0.6%	0.5%	0.6%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	
DIVERSITY (-)					1,300	1,244	1,297	1,346	1,420	1,419	1,293	1,378	1,413	1,525	1,512	
PJM WESTERN		50,986	50,986		51,105	51,511	52,193	52,808	53,360	53,816	54,240	54,786	55,368	56,070	56,519	1.0%
	%					0.8%	1.3%	1.2%	1.0%	0.9%	0.8%	1.0%	1.1%	1.3%	0.8%	
DOM		15,435	15,435	16,650	16,861	17,043	17,395	17,657	17,900	18,146	18,399	18,646	18,927	19,203	19,422	1.4%
	%				1.3%	1.1%	2.1%	1.5%	1.4%	1.4%	1.4%	1.3%	1.5%	1.5%	1.1%	
DIVERSITY (-)					1,052	927	958	1,007	1,017	922	977	849	905	1,053	1,001	
PJM RTO		110,415	110,415	112,455	113,565	114,728	116,408	117,871	119,240	120,569	121,685	123,165	124,545	125,996	127,250	1.1%
	%				1.0%	1.0%	1.5%	1.3%	1.2%	1.1%	0.9%	1.2%	1.1%	1.2%	1.0%	

Note:
Normal 06/07 and all forecast values are non-coincident as estimated by PJM staff.
Normal 06/07 and all forecast values represent unrestricted peaks.

Table B-2 (Continued)

WINTER PEAK LOAD (MW) AND GROWTH RATES FOR
EACH PJM WESTERN AND PJM SOUTHERN GEOGRAPHIC ZONE AND SUM OF GEOGRAPHIC ZONES
2018/19-2022/23

		18/19	**19/20**	**20/21**	**21/22**	**22/23**	**Annual Growth Rate (15 yr)**
AEP		24,540	24,560	24,774	24,968	25,143	0.7%
	%	0.5%	0.1%	0.9%	0.8%	0.7%	
APS		9,181	9,221	9,301	9,377	9,434	0.7%
	%	0.3%	0.4%	0.9%	0.8%	0.6%	
COMED		19,231	19,339	19,644	20,002	20,340	1.6%
	%	1.5%	0.6%	1.6%	1.8%	1.7%	
DAY		3,251	3,254	3,277	3,304	3,323	0.7%
	%	0.5%	0.1%	0.7%	0.8%	0.6%	
DLCO		2,280	2,291	2,303	2,314	2,326	0.5%
	%	0.5%	0.5%	0.5%	0.5%	0.5%	
DIVERSITY (-)		1,576	1,451	1,518	1,570	1,669	
PJM WESTERN		56,907	57,214	57,781	58,395	58,897	1.0%
	%	0.7%	0.5%	1.0%	1.1%	0.9%	
DOM		19,645	19,824	20,047	20,273	20,498	1.3%
	%	1.1%	0.9%	1.1%	1.1%	1.1%	
DIVERSITY (-)		890	818	893	985	991	
PJM RTO		128,497	129,475	130,819	132,219	133,518	1.1%
	%	1.0%	0.8%	1.0%	1.1%	1.0%	

Note:
Normal 06/07 and all forecast values are non-coincident as estimated by PJM staff.
Normal 06/07 and all forecast values represent unrestricted peaks.

Table B-3

SPRING (APRIL) PEAK LOAD (MW) FOR
EACH PJM MID-ATLANTIC GEOGRAPHIC ZONE AND SUM OF GEOGRAPHIC ZONES
2008-2023

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
AE	1,587	1,628	1,675	1,761	1,850	1,924	2,013	2,052	2,087	2,117	2,171	2,205	2,253	2,284	2,315	2,352
BGE	4,940	4,988	5,039	5,056	5,085	5,134	5,205	5,256	5,242	5,252	5,340	5,387	5,449	5,476	5,511	5,495
DPL	2,739	2,785	2,825	2,846	2,887	2,939	2,990	3,040	3,065	3,109	3,179	3,236	3,293	3,321	3,369	3,427
JCPL	3,442	3,515	3,596	3,666	3,719	3,789	3,886	3,980	4,033	4,106	4,165	4,246	4,362	4,430	4,503	4,564
METED	2,269	2,290	2,320	2,348	2,395	2,427	2,454	2,469	2,502	2,542	2,580	2,617	2,626	2,653	2,704	2,761
PECO	5,734	5,869	5,988	5,956	6,056	6,125	6,247	6,373	6,371	6,450	6,534	6,597	6,774	6,881	6,856	6,940
PENLC	2,493	2,519	2,549	2,577	2,608	2,630	2,659	2,680	2,701	2,730	2,745	2,764	2,785	2,803	2,827	2,853
PEPCO	4,548	4,622	4,727	4,689	4,727	4,802	4,898	4,977	4,982	5,035	5,070	5,158	5,256	5,338	5,339	5,366
PL	5,918	5,977	6,065	6,130	6,220	6,303	6,383	6,445	6,529	6,620	6,702	6,786	6,849	6,920	7,010	7,118
PS	6,489	6,648	6,745	6,787	6,895	7,004	7,133	7,265	7,303	7,398	7,513	7,606	7,776	7,831	7,917	8,038
RECO	222	225	225	224	226	227	229	232	229	229	231	232	237	236	235	235
UGI	158	159	160	161	163	165	167	168	169	171	173	175	176	178	180	182
DIVERSITY (-)	1,275	1,296	1,318	1,327	1,347	1,367	1,392	1,413	1,422	1,439	1,459	1,478	1,504	1,521	1,534	1,551
PJM MID-ATLANTIC	39,264	39,929	40,596	40,874	41,484	42,102	42,872	43,524	43,791	44,320	44,944	45,531	46,332	46,830	47,232	47,780
FE/GPU	8,006	8,123	8,261	8,383	8,511	8,632	8,782	8,909	9,013	9,151	9,261	9,394	9,537	9,647	9,792	9,932
PLGRP	6,074	6,134	6,223	6,289	6,381	6,466	6,548	6,611	6,696	6,789	6,873	6,959	7,023	7,096	7,188	7,298

Table B-3

SPRING (APRIL) PEAK LOAD (MW) FOR
EACH PJM WESTERN AND PJM SOUTHERN GEOGRAPHIC ZONE AND SUM OF GEOGRAPHIC ZONES
2008-2023

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
AEP	19,164	19,301	19,533	19,766	20,029	20,212	20,461	20,633	20,839	21,073	21,163	21,265	21,443	21,505	21,628	21,750
APS	7,019	7,056	7,114	7,167	7,234	7,270	7,321	7,352	7,401	7,463	7,501	7,531	7,555	7,587	7,644	7,707
COMED	14,392	14,734	15,070	15,327	15,653	16,080	16,380	16,696	16,967	17,293	17,847	18,233	18,542	18,808	19,032	19,407
DAY	2,576	2,604	2,630	2,642	2,674	2,698	2,725	2,742	2,753	2,781	2,795	2,816	2,838	2,852	2,864	2,888
DLCO	2,014	2,049	2,073	2,040	2,074	2,103	2,121	2,171	2,153	2,128	2,196	2,206	2,257	2,267	2,225	2,230
DIVERSITY (-)	1,209	1,224	1,242	1,256	1,276	1,294	1,312	1,327	1,341	1,358	1,378	1,393	1,409	1,419	1,429	1,445
PJM WESTERN	43,956	44,520	45,178	45,686	46,388	47,069	47,696	48,267	48,772	49,380	50,124	50,658	51,226	51,600	51,964	52,537
DOM	13,404	13,665	13,945	14,156	14,385	14,645	14,901	15,142	15,338	15,610	15,879	16,098	16,246	16,499	16,683	16,949
DIVERSITY (-)	2,967	3,089	3,201	2,622	2,777	2,742	3,217	2,961	2,493	2,585	2,871	2,737	2,928	3,021	2,532	2,646
PJM RTO	93,657	95,025	96,518	98,094	99,480	101,074	102,252	103,972	105,408	106,725	108,076	109,550	110,876	111,908	113,347	114,620

Table B-4

FALL (OCTOBER) PEAK LOAD (MW) FOR
EACH PJM MID-ATLANTIC GEOGRAPHIC ZONE AND SUM OF GEOGRAPHIC ZONES
2008-2023

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
AE	1,665	1,713	1,765	1,900	1,977	2,093	2,135	2,176	2,206	2,268	2,323	2,362	2,399	2,434	2,473	2,528
BGE	4,704	4,763	4,796	4,850	4,958	5,002	5,018	5,038	5,052	5,143	5,226	5,261	5,264	5,279	5,317	5,408
DPL	2,662	2,708	2,748	2,801	2,878	2,924	2,965	3,010	3,057	3,125	3,189	3,241	3,295	3,351	3,401	3,477
JCPL	3,583	3,694	3,749	3,835	3,985	4,081	4,154	4,234	4,269	4,402	4,518	4,616	4,684	4,756	4,827	4,948
METED	2,164	2,201	2,226	2,270	2,319	2,356	2,381	2,405	2,433	2,483	2,530	2,564	2,590	2,616	2,652	2,703
PECO	5,749	5,860	5,945	5,976	6,213	6,305	6,369	6,444	6,471	6,646	6,792	6,871	6,936	7,011	7,045	7,220
PENLC	2,472	2,506	2,530	2,572	2,621	2,625	2,652	2,667	2,695	2,722	2,776	2,767	2,785	2,800	2,829	2,850
PEPCO	4,657	4,725	4,747	4,770	4,928	4,986	5,042	5,087	5,078	5,203	5,321	5,374	5,427	5,454	5,477	5,599
PL	5,658	5,757	5,811	5,894	5,991	6,072	6,127	6,181	6,253	6,359	6,460	6,533	6,574	6,630	6,711	6,829
PS	6,882	7,009	7,051	7,124	7,395	7,529	7,587	7,667	7,669	7,882	8,054	8,167	8,227	8,272	8,329	8,547
RECO	242	243	241	241	251	252	252	252	248	254	259	260	260	257	257	263
UGI	156	157	158	160	162	165	166	166	169	171	173	174	175	176	179	182
DIVERSITY (-)	872	888	898	911	939	954	964	974	980	1,003	1,023	1,036	1,045	1,054	1,064	1,086
PJM MID-ATLANTIC	39,722	40,448	40,869	41,482	42,739	43,436	43,884	44,353	44,620	45,655	46,598	47,154	47,571	47,982	48,433	49,468
FE/GPU	8,072	8,251	8,353	8,522	8,766	8,900	9,023	9,140	9,229	9,435	9,648	9,769	9,879	9,990	10,124	10,313
PLGRP	5,811	5,911	5,966	6,051	6,150	6,234	6,290	6,344	6,419	6,527	6,629	6,703	6,745	6,802	6,886	7,007

Table B-4

FALL (OCTOBER) PEAK LOAD (MW) FOR
EACH PJM WESTERN AND PJM SOUTHERN GEOGRAPHIC ZONE AND SUM OF GEOGRAPHIC ZONES
2008-2023

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
AEP	18,416	18,623	18,734	18,974	19,331	19,536	19,688	19,779	19,914	20,161	20,391	20,545	20,638	20,703	20,837	21,044
APS	6,734	6,800	6,851	6,902	6,983	7,041	7,070	7,095	7,126	7,193	7,261	7,301	7,319	7,346	7,382	7,436
COMED	14,342	14,722	14,985	15,295	15,829	16,202	16,509	16,841	17,098	17,548	18,051	18,344	18,609	18,894	19,192	19,635
DAY	2,518	2,547	2,562	2,595	2,644	2,670	2,689	2,701	2,714	2,752	2,784	2,801	2,812	2,821	2,835	2,866
DLCO	1,939	1,960	1,972	1,989	2,027	2,049	2,063	2,076	2,077	2,114	2,140	2,156	2,169	2,171	2,183	2,217
DIVERSITY (-)	1,276	1,296	1,309	1,328	1,359	1,379	1,394	1,407	1,420	1,444	1,469	1,484	1,496	1,507	1,522	1,544
PJM WESTERN	42,673	43,356	43,795	44,427	45,455	46,119	46,625	47,085	47,509	48,324	49,158	49,663	50,051	50,428	50,907	51,654
DOM	13,432	13,695	13,847	14,109	14,598	14,861	15,097	15,285	15,460	15,850	16,146	16,342	16,536	16,616	16,782	17,156
DIVERSITY (-)	1,429	1,475	1,493	1,515	1,718	1,848	1,957	1,812	1,865	2,020	2,172	2,181	2,213	2,497	2,531	2,191
PJM RTO	94,398	96,024	97,018	98,503	101,074	102,568	103,649	104,911	105,724	107,809	109,730	110,978	111,945	112,529	113,591	116,087

Table B-5

MONTHLY PEAK FORECAST (MW) FOR EACH
PJM MID-ATLANTIC GEOGRAPHIC ZONE AND DIVERSIFIED SUM OF GEOGRAPHIC ZONES

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	MID-ATLANTIC DIVERSITY	PJM MID-ATLANTIC
Jan 2008	1,845	6,009	3,397	4,010	2,575	6,602	2,820	5,381	7,232	7,070	229	201	720	46,651
Feb 2008	1,776	5,778	3,293	3,819	2,509	6,367	2,756	5,197	6,982	6,812	216	192	699	44,998
Mar 2008	1,628	5,228	2,942	3,584	2,386	5,916	2,624	4,600	6,418	6,438	213	174	448	41,703
Apr 2008	1,587	4,940	2,739	3,442	2,269	5,734	2,493	4,548	5,918	6,489	222	158	1,275	39,264
May 2008	1,907	5,700	3,096	4,544	2,421	6,733	2,411	5,627	5,916	8,360	328	151	745	46,449
Jun 2008	2,486	6,671	3,804	5,777	2,760	8,117	2,751	6,532	6,853	10,027	394	182	490	55,864
Jul 2008	2,829	7,344	4,192	6,478	2,929	8,759	2,850	7,057	7,292	10,967	435	197	594	60,735
Aug 2008	2,703	6,990	4,024	5,831	2,821	8,382	2,793	6,742	6,999	10,104	387	187	557	57,406
Sep 2008	2,289	6,239	3,449	5,081	2,503	7,278	2,602	6,030	6,345	9,041	332	170	832	50,527
Oct 2008	1,665	4,704	2,662	3,583	2,164	5,749	2,472	4,657	5,658	6,882	242	156	872	39,722
Nov 2008	1,624	4,836	2,765	3,554	2,248	5,817	2,571	4,451	6,097	6,493	217	171	413	40,431
Dec 2008	1,880	5,705	3,261	4,046	2,533	6,518	2,812	5,159	6,941	7,108	242	201	291	46,115
	AE	**BGE**	**DPL**	**JCPL**	**METED**	**PECO**	**PENLC**	**PEPCO**	**PL**	**PS**	**RECO**	**UGI**	**DIVERSITY**	**MID-ATLANTIC**
Jan 2009	1,879	6,047	3,442	4,066	2,596	6,682	2,835	5,432	7,281	7,137	229	202	727	47,101
Feb 2009	1,812	5,801	3,339	3,877	2,529	6,449	2,770	5,229	7,025	6,879	216	193	705	45,414
Mar 2009	1,664	5,278	2,989	3,654	2,411	6,064	2,648	4,679	6,486	6,579	214	175	455	42,386
Apr 2009	1,628	4,988	2,785	3,515	2,290	5,869	2,519	4,622	5,977	6,648	225	159	1,296	39,929
May 2009	1,957	5,746	3,151	4,646	2,452	6,850	2,434	5,690	5,982	8,496	329	152	756	47,129
Jun 2009	2,548	6,788	3,879	5,920	2,806	8,250	2,786	6,614	6,962	10,178	399	184	498	56,816
Jul 2009	2,897	7,455	4,278	6,636	2,982	8,909	2,892	7,159	7,420	11,158	441	199	604	61,822
Aug 2009	2,765	7,082	4,103	5,988	2,868	8,515	2,834	6,830	7,118	10,264	392	189	566	58,382
Sep 2009	2,355	6,343	3,539	5,222	2,558	7,447	2,649	6,137	6,479	9,227	336	172	849	51,615
Oct 2009	1,713	4,763	2,708	3,694	2,201	5,860	2,506	4,725	5,757	7,009	243	157	888	40,448
Nov 2009	1,679	4,933	2,851	3,667	2,305	5,957	2,622	4,535	6,231	6,633	218	174	422	41,383
Dec 2009	1,925	5,801	3,335	4,152	2,578	6,639	2,855	5,238	7,061	7,237	243	203	296	46,971
	AE	**BGE**	**DPL**	**JCPL**	**METED**	**PECO**	**PENLC**	**PEPCO**	**PL**	**PS**	**RECO**	**UGI**	**DIVERSITY**	**MID-ATLANTIC**
Jan 2010	1,919	6,105	3,497	4,150	2,634	6,780	2,874	5,501	7,374	7,249	229	204	738	47,778
Feb 2010	1,858	5,881	3,405	3,975	2,576	6,567	2,815	5,313	7,153	7,021	218	195	718	46,259
Mar 2010	1,727	5,357	3,051	3,771	2,445	6,236	2,679	4,820	6,579	6,712	216	177	465	43,305
Apr 2010	1,675	5,039	2,825	3,596	2,320	5,988	2,549	4,727	6,065	6,745	225	160	1,318	40,596
May 2010	2,022	5,812	3,207	4,769	2,491	6,960	2,466	5,740	6,089	8,637	333	154	768	47,912
Jun 2010	2,623	6,890	3,959	6,132	2,875	8,412	2,829	6,735	7,093	10,416	407	186	509	58,048
Jul 2010	2,975	7,555	4,360	6,804	3,044	9,055	2,930	7,252	7,536	11,340	447	202	615	62,885
Aug 2010	2,838	7,189	4,176	6,151	2,931	8,661	2,870	6,929	7,226	10,443	397	192	576	59,427
Sep 2010	2,419	6,413	3,596	5,329	2,604	7,551	2,678	6,202	6,561	9,354	339	174	862	52,358
Oct 2010	1,765	4,796	2,748	3,749	2,226	5,945	2,530	4,747	5,811	7,051	241	158	898	40,869
Nov 2010	1,723	4,980	2,890	3,739	2,341	6,044	2,651	4,581	6,303	6,721	218	176	428	41,939
Dec 2010	1,964	5,831	3,369	4,227	2,621	6,736	2,904	5,288	7,138	7,360	243	204	300	47,585

Table B-5

MONTHLY PEAK FORECAST (MW) FOR EACH
PJM WESTERN AND PJM SOUTHERN GEOGRAPHIC ZONE AND DIVERSIFIED SUM OF GEOGRAPHIC ZONES

						WESTERN	PJM		RTO	
	AEP	**APS**	**COMED**	**DAY**	**DLCO**	**DIVERSITY**	**WESTERN**	**DOM**	**DIVERSITY**	**PJM RTO**
Jan 2008	22,588	8,523	15,850	3,012	2,142	1,010	51,105	16,861	1,052	113,565
Feb 2008	21,957	8,252	15,367	2,909	2,081	783	49,783	16,253	1,742	109,292
Mar 2008	20,435	7,516	14,455	2,677	1,989	790	46,282	14,188	2,633	99,540
Apr 2008	19,164	7,019	14,392	2,576	2,014	1,209	43,956	13,404	2,967	93,657
May 2008	19,831	6,956	16,828	2,824	2,283	1,217	47,505	15,358	4,558	104,754
Jun 2008	22,796	8,254	21,665	3,388	2,771	1,200	57,674	17,988	3,766	127,760
Jul 2008	23,939	8,688	23,654	3,597	2,942	1,413	61,407	19,353	3,547	137,948
Aug 2008	23,350	8,394	22,538	3,485	2,798	420	60,145	18,632	5,283	130,900
Sep 2008	21,304	7,709	19,453	3,151	2,530	703	53,444	16,443	3,980	116,434
Oct 2008	18,416	6,734	14,342	2,518	1,939	1,276	42,673	13,432	1,429	94,398
Nov 2008	19,356	7,191	14,577	2,609	1,951	629	45,055	13,420	806	98,100
Dec 2008	21,734	8,285	16,331	2,940	2,165	514	50,941	15,963	1,582	111,437
	AEP	**APS**	**COMED**	**DAY**	**DLCO**	**DIVERSITY**	**WESTERN**	**DOM**	**DIVERSITY**	**PJM RTO**
Jan 2009	22,677	8,558	16,117	3,024	2,154	1,019	51,511	17,043	927	114,728
Feb 2009	21,965	8,273	15,658	2,915	2,089	789	50,111	16,375	1,502	110,398
Mar 2009	20,583	7,568	14,756	2,704	2,018	799	46,830	14,489	2,696	101,009
Apr 2009	19,301	7,056	14,734	2,604	2,049	1,224	44,520	13,665	3,089	95,025
May 2009	19,998	6,993	17,232	2,850	2,301	1,233	48,141	15,609	4,636	106,243
Jun 2009	23,083	8,321	22,131	3,423	2,804	1,218	58,544	18,278	3,684	129,954
Jul 2009	24,311	8,783	24,219	3,644	2,978	1,438	62,497	19,743	3,655	140,407
Aug 2009	23,704	8,470	22,994	3,528	2,819	427	61,088	19,002	5,389	133,083
Sep 2009	21,669	7,856	19,967	3,208	2,571	718	54,553	16,874	4,186	118,856
Oct 2009	18,623	6,800	14,722	2,547	1,960	1,296	43,356	13,695	1,475	96,024
Nov 2009	19,716	7,323	14,996	2,661	1,974	643	46,027	13,878	855	100,433
Dec 2009	22,041	8,385	16,657	2,976	2,176	522	51,713	16,332	1,847	113,169
	AEP	**APS**	**COMED**	**DAY**	**DLCO**	**DIVERSITY**	**WESTERN**	**DOM**	**DIVERSITY**	**PJM RTO**
Jan 2010	22,950	8,651	16,401	3,056	2,167	1,032	52,193	17,395	958	116,408
Feb 2010	22,326	8,381	15,995	2,953	2,108	802	50,961	16,810	1,798	112,232
Mar 2010	20,791	7,646	15,188	2,730	2,036	812	47,579	14,819	2,768	102,935
Apr 2010	19,533	7,114	15,070	2,630	2,073	1,242	45,178	13,945	3,201	96,518
May 2010	20,265	7,073	17,675	2,887	2,325	1,254	48,971	15,955	4,762	108,076
Jun 2010	23,558	8,408	22,691	3,474	2,849	1,243	59,737	18,744	3,820	132,709
Jul 2010	24,640	8,872	24,693	3,688	3,013	1,460	63,446	20,192	3,639	142,884
Aug 2010	24,148	8,550	23,593	3,571	2,864	435	62,291	19,435	5,520	135,633
Sep 2010	21,921	7,900	20,366	3,235	2,588	727	55,283	17,188	3,964	120,865
Oct 2010	18,734	6,851	14,985	2,562	1,972	1,309	43,795	13,847	1,493	97,018
Nov 2010	19,916	7,389	15,284	2,688	1,992	651	46,618	14,116	624	102,049
Dec 2010	22,270	8,485	16,955	3,010	2,188	529	52,379	16,579	1,598	114,945

Table B-6

MONTHLY PEAK FORECAST (MW)
FOR FE/GPU AND PLGRP

	FE/GPU	PLGRP
Jan 2008	9,335	7,429
Feb 2008	9,011	7,170
Mar 2008	8,540	6,591
Apr 2008	8,006	6,074
May 2008	9,146	6,062
Jun 2008	11,150	7,034
Jul 2008	12,086	7,486
Aug 2008	11,308	7,182
Sep 2008	10,038	6,509
Oct 2008	8,072	5,811
Nov 2008	8,328	6,265
Dec 2008	9,326	7,139

	FE/GPU	PLGRP
Jan 2009	9,427	7,479
Feb 2009	9,103	7,214
Mar 2009	8,658	6,660
Apr 2009	8,123	6,134
May 2009	9,298	6,129
Jun 2009	11,372	7,145
Jul 2009	12,335	7,616
Aug 2009	11,550	7,303
Sep 2009	10,277	6,645
Oct 2009	8,251	5,911
Nov 2009	8,547	6,402
Dec 2009	9,518	7,261

	FE/GPU	PLGRP
Jan 2010	9,587	7,574
Feb 2010	9,291	7,344
Mar 2010	8,839	6,754
Apr 2010	8,261	6,223
May 2010	9,487	6,238
Jun 2010	11,692	7,278
Jul 2010	12,599	7,735
Aug 2010	11,809	7,414
Sep 2010	10,457	6,729
Oct 2010	8,353	5,966
Nov 2010	8,684	6,476
Dec 2010	9,684	7,339

TABLE B-7

TREATMENT OF PJM MID-ATLANTIC LOAD MANAGEMENT IN PLANNING (MW)
PLACED UNDER PJM COORDINATION - SUMMER

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
AE																
a) CONTRACTUALLY INTERRUPTIBLE	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
b) DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
BGE																
a) CONTRACTUALLY INTERRUPTIBLE	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
b) DIRECT CONTROL	210	210	210	210	210	210	210	210	210	210	210	210	210	210	210	210
TOTAL	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260
DPL																
a) CONTRACTUALLY INTERRUPTIBLE	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
b) DIRECT CONTROL	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35
TOTAL	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
JCPL																
a) CONTRACTUALLY INTERRUPTIBLE	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
b) DIRECT CONTROL	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47
TOTAL	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57
METED																
a) CONTRACTUALLY INTERRUPTIBLE	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
b) DIRECT CONTROL	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
TOTAL	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47
PECO																
a) CONTRACTUALLY INTERRUPTIBLE	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190
b) DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190
PENLC																
a) CONTRACTUALLY INTERRUPTIBLE	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
b) DIRECT CONTROL	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
TOTAL	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
PEPCO																
a) CONTRACTUALLY INTERRUPTIBLE	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
b) DIRECT CONTROL	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
TOTAL	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28
PL																
a) CONTRACTUALLY INTERRUPTIBLE	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
b) DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
PS																
a) CONTRACTUALLY INTERRUPTIBLE	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
b) DIRECT CONTROL	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62
TOTAL	112	112	112	112	112	112	112	112	112	112	112	112	112	112	112	112
RECO																
a) CONTRACTUALLY INTERRUPTIBLE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b) DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
UGI																
a) CONTRACTUALLY INTERRUPTIBLE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b) DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PJM MID-ATLANTIC																
a) CONTRACTUALLY INTERRUPTIBLE	646	646	646	646	646	646	646	646	646	646	646	646	646	646	646	646
b) DIRECT CONTROL	372	372	372	372	372	372	372	372	372	372	372	372	372	372	372	372
TOTAL	1,018	1,018	1,018	1,018	1,018	1,018	1,018	1,018	1,018	1,018	1,018	1,018	1,018	1,018	1,018	1,018

Note: Forecast represents Load Management credits from summer 2007, and are held constant for the forecast perio

TABLE B-7

TREATMENT OF PJM WESTERN AND PJM SOUTHERN LOAD MANAGEMENT IN PLANNING (MW)
PLACED UNDER PJM COORDINATION - SUMMER

	2008	2009	2010	2011	2012	2013	2014	2015
AEP								
a) CONTRACTUALLY INTERRUPTIBLE	550	550	550	550	550	550	550	550
b) DIRECT CONTROL	0	0	0	0	0	0	0	0
TOTAL	550	550	550	550	550	550	550	550
APS								
a) CONTRACTUALLY INTERRUPTIBLE	110	110	110	110	110	110	110	110
b) DIRECT CONTROL	0	0	0	0	0	0	0	0
TOTAL	110	110	110	110	110	110	110	110
COMED								
a) CONTRACTUALLY INTERRUPTIBLE	420	420	420	420	420	420	420	420
b) DIRECT CONTROL	55	55	55	55	55	55	55	55
TOTAL	475	475	475	475	475	475	475	475
DAY								
a) CONTRACTUALLY INTERRUPTIBLE	2	2	2	2	2	2	2	2
b) DIRECT CONTROL	0	0	0	0	0	0	0	0
TOTAL	2	2	2	2	2	2	2	2
DLCO								
a) CONTRACTUALLY INTERRUPTIBLE	2	2	2	2	2	2	2	2
b) DIRECT CONTROL	0	0	0	0	0	0	0	0
TOTAL	2	2	2	2	2	2	2	2
PJM WESTERN								
a) CONTRACTUALLY INTERRUPTIBLE	1,084	1,084	1,084	1,084	1,084	1,084	1,084	1,084
b) DIRECT CONTROL	55	55	55	55	55	55	55	55
TOTAL	1,139	1,139	1,139	1,139	1,139	1,139	1,139	1,139
DOM								
a) CONTRACTUALLY INTERRUPTIBLE	11	11	11	11	11	11	11	11
b) DIRECT CONTROL	0	0	0	0	0	0	0	0
TOTAL	11	11	11	11	11	11	11	11
PJM RTO								
a) CONTRACTUALLY INTERRUPTIBLE	1,741	1,741	1,741	1,741	1,741	1,741	1,741	1,741
b) DIRECT CONTROL	427	427	427	427	427	427	427	427
TOTAL	2,168	2,168	2,168	2,168	2,168	2,168	2,168	2,168

	2016	2017	2018	2019	2020	2021	2022	2023
AEP								
a) CONTRACTUALLY INTERRUPTIBLE	550	550	550	550	550	550	550	550
b) DIRECT CONTROL	0	0	0	0	0	0	0	0
TOTAL	550	550	550	550	550	550	550	550
APS								
a) CONTRACTUALLY INTERRUPTIBLE	110	110	110	110	110	110	110	110
b) DIRECT CONTROL	0	0	0	0	0	0	0	0
TOTAL	110	110	110	110	110	110	110	110
COMED								
a) CONTRACTUALLY INTERRUPTIBLE	420	420	420	420	420	420	420	420
b) DIRECT CONTROL	55	55	55	55	55	55	55	55
TOTAL	475	475	475	475	475	475	475	475
DAY								
a) CONTRACTUALLY INTERRUPTIBLE	2	2	2	2	2	2	2	2
b) DIRECT CONTROL	0	0	0	0	0	0	0	0
TOTAL	2	2	2	2	2	2	2	2
DLCO								
a) CONTRACTUALLY INTERRUPTIBLE	2	2	2	2	2	2	2	2
b) DIRECT CONTROL	0	0	0	0	0	0	0	0
TOTAL	2	2	2	2	2	2	2	2
PJM WESTERN								
a) CONTRACTUALLY INTERRUPTIBLE	1,084	1,084	1,084	1,084	1,084	1,084	1,084	1,084
b) DIRECT CONTROL	55	55	55	55	55	55	55	55
TOTAL	1,139	1,139	1,139	1,139	1,139	1,139	1,139	1,139
DOM								
a) CONTRACTUALLY INTERRUPTIBLE	11	11	11	11	11	11	11	11
b) DIRECT CONTROL	0	0	0	0	0	0	0	0
TOTAL	11	11	11	11	11	11	11	11
PJM RTO								
a) CONTRACTUALLY INTERRUPTIBLE	1,741	1,741	1,741	1,741	1,741	1,741	1,741	1,741
b) DIRECT CONTROL	427	427	427	427	427	427	427	427
TOTAL	2,168	2,168	2,168	2,168	2,168	2,168	2,168	2,168

Note: Forecast represents Load Management credits from summer 2007, and are held constant for the forecast period.

Table B-8

**SUMMER COINCIDENT PEAK LOAD (MW) FOR
EACH PJM GEOGRAPHIC ZONE,
LOAD DELIVERABILITY AREA AND RTO
2008-2023**

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
AE	2,730	2,797	2,875	3,059	3,124	3,259	3,340	3,401	3,474	3,525	3,579	3,633	3,689	3,748	3,824	3,873
BGE	7,065	7,171	7,271	7,347	7,415	7,492	7,570	7,644	7,695	7,773	7,832	7,914	7,989	8,053	8,121	8,199
DPL	4,039	4,122	4,204	4,284	4,369	4,453	4,534	4,617	4,708	4,808	4,882	4,980	5,067	5,166	5,268	5,374
JCPL	6,231	6,381	6,536	6,671	6,792	6,929	7,064	7,202	7,346	7,486	7,610	7,736	7,869	8,013	8,160	8,307
METED	2,814	2,865	2,925	2,974	3,017	3,065	3,112	3,162	3,216	3,266	3,308	3,363	3,419	3,474	3,533	3,586
PECO	8,429	8,575	8,723	8,850	8,980	9,100	9,224	9,356	9,483	9,613	9,734	9,852	9,972	10,094	10,233	10,364
PENLC	2,719	2,758	2,800	2,830	2,860	2,890	2,919	2,949	2,977	3,006	3,028	3,053	3,079	3,104	3,130	3,157
PEPCO	6,800	6,898	6,996	7,076	7,171	7,273	7,375	7,481	7,570	7,671	7,771	7,876	7,980	8,076	8,180	8,282
PL	7,011	7,126	7,253	7,356	7,452	7,558	7,658	7,766	7,876	7,986	8,089	8,203	8,317	8,429	8,548	8,667
PS	10,581	10,758	10,943	11,108	11,251	11,426	11,585	11,747	11,908	12,066	12,209	12,370	12,532	12,694	12,869	13,049
RECO	417	424	430	435	440	445	451	456	462	467	470	477	482	488	493	498
UGI	189	191	194	196	198	200	202	205	207	210	212	214	217	219	222	224
AEP	22,943	23,281	23,620	23,879	24,144	24,392	24,632	24,919	25,170	25,377	25,586	25,778	25,994	26,194	26,401	26,571
APS	8,356	8,445	8,538	8,615	8,705	8,785	8,862	8,939	9,001	9,080	9,144	9,211	9,282	9,346	9,405	9,485
COMED	22,731	23,288	23,722	24,140	24,572	25,082	25,573	26,085	26,532	26,995	27,442	27,888	28,376	28,812	29,247	29,719
DAY	3,426	3,469	3,515	3,545	3,584	3,623	3,657	3,691	3,721	3,752	3,777	3,810	3,838	3,862	3,886	3,912
DLCO	2,817	2,850	2,885	2,913	2,942	2,975	3,003	3,033	3,060	3,089	3,115	3,141	3,171	3,197	3,222	3,251
DOM	18,650	19,008	19,454	19,783	20,167	20,548	20,914	21,280	21,624	22,006	22,319	22,633	22,936	23,210	23,516	23,849
PJM RTO	137,948	140,407	142,884	145,061	147,183	149,495	151,675	153,933	156,030	158,176	160,107	162,132	164,209	166,179	168,258	170,367
Eastern MAAC	32,427	33,057	33,711	34,407	34,956	35,612	36,198	36,779	37,381	37,965	38,484	39,048	39,611	40,203	40,847	41,465
Southwest MAAC	13,865	14,069	14,267	14,423	14,586	14,765	14,945	15,125	15,265	15,444	15,603	15,790	15,969	16,129	16,301	16,481
MAAC and APS	67,381	68,511	69,688	70,801	71,774	72,875	73,896	74,925	75,923	76,957	77,868	78,882	79,894	80,904	81,986	83,065

Notes: Load values presented here are coincident with the PJM RTO peak.
This table will be used for the Reliability Pricing Model.

TABLE C-1

PJM LOAD DELIVERABILITY AREAS
CENTRAL MID-ATLANTIC: BGE, METED, PEPCO, PL AND UGI
50/50 SEASONAL PEAKS - MW

YEAR	SPRING (WK 14-19)	SUMMER (WK 20-39)	FALL (WK 40-45)	WINTER (WK 46-13)
2008	17,372	24,611	16,893	21,245
2009	17,570	25,003	17,150	21,404
2010	17,838	25,374	17,282	21,662
2011	17,909	25,685	17,482	21,900
2012	18,110	25,965	17,886	22,099
2013	18,344	26,348	18,103	22,271
2014	18,613	26,672	18,252	22,452
2015	18,816	27,003	18,391	22,646
2016	18,922	27,314	18,497	22,871
2017	19,113	27,638	18,861	23,116
2018	19,352	27,957	19,203	23,313
2019	19,603	28,338	19,394	23,514
2020	19,830	28,688	19,515	23,672
2021	20,034	29,003	19,637	23,907
2022	20,208	29,365	19,813	24,167
2023	20,381	29,716	20,188	24,393

TABLE C-2

PJM LOAD DELIVERABILITY AREAS
WESTERN MID-ATLANTIC: METED, PENLC, PL AND UGI
50/50 SEASONAL PEAKS - MW

YEAR	SPRING (WK 14-19)	SUMMER (WK 20-39)	FALL (WK 40-45)	WINTER (WK 46-13)
2008	10,696	13,186	10,347	12,782
2009	10,801	13,410	10,516	12,868
2010	10,948	13,628	10,619	13,039
2011	11,069	13,818	10,788	13,201
2012	11,236	13,966	10,983	13,335
2013	11,374	14,182	11,107	13,452
2014	11,510	14,360	11,214	13,548
2015	11,608	14,550	11,306	13,680
2016	11,745	14,746	11,436	13,818
2017	11,905	14,923	11,619	13,990
2018	12,040	15,094	11,821	14,111
2019	12,180	15,308	11,919	14,244
2020	12,273	15,512	12,004	14,329
2021	12,389	15,702	12,101	14,486
2022	12,554	15,913	12,249	14,656
2023	12,744	16,109	12,440	14,803

TABLE C-3

PJM LOAD DELIVERABILITY AREAS
EASTERN MID-ATLANTIC: AE, DPL, JCPL, PECO, PS AND RECO
50/50 SEASONAL PEAKS - MW

YEAR	SPRING (WK 14-19)	SUMMER (WK 20-39)	FALL (WK 40-45)	WINTER (WK 46-13)
2008	19,701	33,510	20,550	22,920
2009	20,146	34,166	20,989	23,200
2010	20,520	34,825	21,258	23,585
2011	20,702	35,521	21,632	23,945
2012	21,085	36,049	22,444	24,303
2013	21,450	36,735	22,924	24,641
2014	21,928	37,351	23,199	24,941
2015	22,361	37,919	23,516	25,283
2016	22,503	38,521	23,652	25,607
2017	22,816	39,096	24,302	25,950
2018	23,190	39,632	24,853	26,269
2019	23,511	40,233	25,231	26,572
2020	24,069	40,807	25,512	26,829
2021	24,350	41,403	25,789	27,200
2022	24,557	42,035	26,037	27,563
2023	24,908	42,657	26,681	27,893

TABLE C-4

PJM LOAD DELIVERABILITY AREAS
SOUTHERN MID-ATLANTIC: BGE AND PEPCO
50/50 SEASONAL PEAKS - MW

YEAR	SPRING (WK 14-19)	SUMMER (WK 20-39)	FALL (WK 40-45)	WINTER (WK 46-13)
2008	9,371	14,347	9,265	11,355
2009	9,492	14,559	9,391	11,444
2010	9,646	14,752	9,445	11,570
2011	9,625	14,905	9,522	11,688
2012	9,691	15,061	9,785	11,784
2013	9,814	15,267	9,886	11,867
2014	9,979	15,445	9,957	11,967
2015	10,107	15,615	10,021	12,057
2016	10,098	15,760	10,026	12,173
2017	10,161	15,933	10,240	12,284
2018	10,282	16,104	10,439	12,381
2019	10,415	16,299	10,526	12,476
2020	10,573	16,473	10,582	12,557
2021	10,681	16,625	10,623	12,663
2022	10,717	16,802	10,683	12,787
2023	10,727	16,983	10,894	12,893

TABLE C-5

PJM LOAD DELIVERABILITY AREAS
MID-ATLANTIC and APS: AE, APS, BGE, DPL, JCPL, METED, PECO, PENLC, PEPCO, PL, PS, RECO, and UGI
50/50 SEASONAL PEAKS - MW

YEAR	SPRING (WK 14-19)	SUMMER (WK 20-39)	FALL (WK 40-45)	WINTER (WK 46-13)
2008	46,108	69,212	46,202	55,026
2009	46,809	70,391	46,991	55,510
2010	47,533	71,540	47,461	56,279
2011	47,863	72,651	48,122	57,005
2012	48,539	73,556	49,455	57,654
2013	49,192	74,749	50,208	58,217
2014	50,012	75,793	50,683	58,758
2015	50,695	76,786	51,175	59,376
2016	51,010	77,784	51,472	60,025
2017	51,599	78,773	52,570	60,731
2018	52,260	79,709	53,577	61,306
2019	52,877	80,786	54,171	61,856
2020	53,702	81,804	54,604	62,315
2021	54,232	82,795	55,041	63,023
2022	54,690	83,873	55,526	63,749
2023	55,299	84,939	56,610	64,383

Table D-1

SUMMER 90/10 PEAK LOAD (MW) FOR
EACH PJM MID-ATLANTIC GEOGRAPHIC ZONE AND SUM OF GEOGRAPHIC ZONES
2008-2023

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
AE	2,992	3,065	3,138	3,319	3,398	3,535	3,630	3,690	3,746	3,810	3,876	3,930	3,992	4,050	4,108	4,170
BGE	7,585	7,702	7,812	7,893	7,974	8,044	8,122	8,202	8,268	8,341	8,424	8,491	8,569	8,642	8,710	8,783
DPL	4,407	4,503	4,583	4,668	4,755	4,849	4,951	5,049	5,137	5,233	5,315	5,432	5,556	5,660	5,760	5,865
JCPL	6,884	7,056	7,208	7,353	7,429	7,594	7,803	7,958	8,087	8,239	8,306	8,478	8,687	8,824	8,971	9,132
METED	3,040	3,095	3,156	3,203	3,251	3,302	3,356	3,409	3,459	3,512	3,565	3,622	3,682	3,738	3,792	3,849
PECO	9,211	9,373	9,524	9,642	9,759	9,911	10,054	10,196	10,317	10,453	10,560	10,718	10,853	10,987	11,114	11,253
PENLC	2,951	2,995	3,031	3,059	3,090	3,107	3,146	3,184	3,206	3,226	3,263	3,274	3,315	3,342	3,354	3,371
PEPCO	7,383	7,499	7,604	7,693	7,799	7,900	8,013	8,130	8,234	8,347	8,463	8,570	8,683	8,793	8,895	9,013
PL	7,568	7,694	7,823	7,916	7,996	8,131	8,252	8,370	8,467	8,554	8,669	8,815	8,950	9,066	9,174	9,280
PS	11,496	11,710	11,901	12,053	12,148	12,332	12,608	12,796	12,932	13,110	13,196	13,371	13,663	13,832	13,997	14,189
RECO	462	469	475	480	485	490	497	503	507	513	518	523	530	534	539	545
UGI	205	208	210	212	214	217	219	222	223	226	228	231	234	236	238	240
DIVERSITY (-)	630	645	654	665	681	672	685	699	712	719	737	730	745	758	765	771
PJM MID-ATLANTIC	63,554	64,724	65,811	66,826	67,617	68,740	69,966	71,010	71,871	72,845	73,646	74,725	75,969	76,946	77,887	78,919
FE/GPU	12,686	12,950	13,197	13,413	13,558	13,807	14,104	14,342	14,537	14,761	14,905	15,159	15,463	15,676	15,888	16,123
PLGRP	7,770	7,898	8,029	8,124	8,206	8,344	8,467	8,588	8,686	8,776	8,893	9,042	9,180	9,298	9,408	9,516

Table D-1

SUMMER 90/10 PEAK LOAD (MW) FOR
EACH PJM WESTERN AND PJM SOUTHERN GEOGRAPHIC ZONE AND SUM OF GEOGRAPHIC ZONES
2008-2023

	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
AEP	24,623	25,033	25,451	25,681	25,984	26,276	26,531	26,832	27,119	27,407	27,648	27,871	28,090	28,310	28,500	28,747
APS	8,936	9,040	9,132	9,210	9,314	9,374	9,453	9,536	9,606	9,681	9,773	9,818	9,889	9,954	10,023	10,093
COMED	25,024	25,604	26,138	26,604	27,107	27,558	28,048	28,598	29,104	29,605	30,113	30,522	30,998	31,487	32,017	32,541
DAY	3,720	3,769	3,815	3,851	3,897	3,928	3,965	4,004	4,036	4,070	4,105	4,130	4,159	4,186	4,210	4,238
DLCO	3,100	3,137	3,174	3,205	3,241	3,269	3,300	3,333	3,363	3,394	3,428	3,451	3,481	3,510	3,538	3,568
DIVERSITY (-)	1,259	1,277	1,224	1,009	1,388	1,580	1,525	1,501	1,080	1,317	1,548	1,661	1,611	1,405	1,124	1,581
PJM WESTERN	64,144	65,306	66,486	67,542	68,155	68,825	69,772	70,802	72,148	72,840	73,519	74,131	75,006	76,042	77,164	77,606
DOM	19,730	20,150	20,618	20,969	21,385	21,759	22,150	22,558	22,938	23,322	23,692	24,000	24,313	24,620	24,922	25,250
DIVERSITY (-)	963	1,066	1,163	1,248	867	522	731	887	1,249	1,024	830	623	857	1,086	1,228	795
PJM RTO	146,465	149,114	151,752	154,089	156,290	158,802	161,157	163,483	165,708	167,983	170,027	172,233	174,431	176,522	178,745	180,980

Table D-2

WINTER 90/10 PEAK LOAD (MW) FOR
EACH PJM MID-ATLANTIC GEOGRAPHIC ZONE AND SUM OF GEOGRAPHIC ZONES
2007/08- 2022/23

	07/08	08/09	09/010	010/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23
AE	1,938	1,959	1,996	2,037	2,133	2,173	2,228	2,273	2,303	2,344	2,371	2,412	2,425	2,456	2,494	2,526
BGE	6,334	6,349	6,403	6,463	6,496	6,542	6,566	6,591	6,622	6,667	6,706	6,744	6,768	6,809	6,850	6,891
DPL	3,627	3,670	3,717	3,777	3,825	3,878	3,929	3,980	4,027	4,090	4,142	4,197	4,249	4,308	4,378	4,447
JCPL	4,161	4,201	4,277	4,360	4,425	4,499	4,555	4,611	4,668	4,755	4,812	4,889	4,927	5,006	5,086	5,167
METED	2,679	2,703	2,725	2,782	2,815	2,846	2,875	2,904	2,920	2,976	3,010	3,043	3,077	3,114	3,151	3,189
PECO	6,872	6,908	7,028	7,135	7,223	7,300	7,358	7,415	7,510	7,623	7,699	7,771	7,810	7,903	7,998	8,094
PENLC	2,915	2,929	2,959	3,005	3,039	3,068	3,088	3,108	3,131	3,172	3,183	3,220	3,234	3,266	3,299	3,332
PEPCO	5,696	5,730	5,795	5,881	5,943	6,010	6,065	6,121	6,182	6,276	6,337	6,416	6,467	6,538	6,610	6,683
PL	7,611	7,652	7,726	7,837	7,898	7,959	8,015	8,070	8,130	8,236	8,300	8,371	8,422	8,484	8,593	8,666
PS	7,279	7,321	7,423	7,541	7,630	7,746	7,816	7,886	7,962	8,073	8,162	8,275	8,322	8,422	8,523	8,625
RECO	246	247	247	248	249	250	251	252	253	254	254	255	256	257	258	259
UGI	210	211	213	215	217	218	220	221	222	225	227	228	229	231	233	235
DIVERSITY (-)	798	772	782	835	863	882	835	854	877	946	934	997	902	955	987	1,014
PJM MID-ATLANTIC	48,770	49,108	49,727	50,446	51,030	51,607	52,131	52,578	53,053	53,745	54,269	54,824	55,284	55,839	56,486	57,100
FE/GPU	9,676	9,760	9,887	10,060	10,193	10,314	10,440	10,544	10,630	10,798	10,896	11,040	11,153	11,264	11,398	11,538
PLGRP	7,817	7,859	7,935	8,048	8,111	8,173	8,231	8,287	8,348	8,457	8,523	8,595	8,647	8,711	8,822	8,897

Table D-2

WINTER 90/10 PEAK LOAD (MW) FOR
EACH PJM WESTERN AND PJM SOUTHERN GEOGRAPHIC ZONE AND SUM OF GEOGRAPHIC ZONES
2007/08- 2022/23

	07/08	08/09	09/010	010/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23
AEP	24,218	24,422	24,543	24,749	24,933	25,165	25,347	25,528	25,662	25,796	25,944	26,128	26,256	26,466	26,678	26,892
APS	9,139	9,182	9,249	9,345	9,409	9,493	9,555	9,618	9,663	9,737	9,800	9,864	9,895	9,964	10,034	10,104
COMED	16,736	16,839	17,113	17,451	17,728	18,040	18,232	18,425	18,670	19,059	19,307	19,667	19,748	20,064	20,385	20,712
DAY	3,207	3,239	3,265	3,276	3,302	3,324	3,350	3,376	3,391	3,401	3,417	3,439	3,448	3,472	3,497	3,521
DLCO	2,238	2,242	2,251	2,265	2,269	2,279	2,288	2,303	2,307	2,316	2,326	2,335	2,345	2,354	2,363	2,373
DIVERSITY (-)	1,243	1,087	1,109	1,248	1,309	1,383	1,415	1,278	1,307	1,456	1,479	1,578	1,454	1,580	1,613	1,703
PJM WESTERN	54,295	54,837	55,312	55,838	56,332	56,918	57,357	57,972	58,386	58,853	59,315	59,855	60,238	60,740	61,344	61,899
DOM	18,103	18,249	18,566	18,873	19,137	19,430	19,554	19,898	20,144	20,454	20,674	20,946	21,134	21,287	21,533	21,771
DIVERSITY (-)	575	326	243	250	369	524	504	187	102	265	228	349	458	145	269	537
PJM RTO	120,593	121,868	123,362	124,907	126,130	127,431	128,538	130,261	131,481	132,787	134,030	135,276	136,198	137,721	139,094	140,233

Table E-1

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR EACH PJM MID-ATLANTIC GEOGRAPHIC ZONE AND SUM OF GEOGRAPHIC ZONES 2008-2018

	ESTIMATED 2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Annual Growth Rate (10 yr)
AE	11,757	12,079	12,342	12,682	13,296	13,802	14,294	14,710	14,968	15,269	15,492	15,743	2.7%
%		2.7%	2.2%	2.8%	4.8%	3.8%	3.6%	2.9%	1.8%	2.0%	1.5%	1.6%	
BGE	34,967	35,351	35,670	36,140	36,511	36,929	37,123	37,450	37,738	38,140	38,345	38,650	0.9%
%		1.1%	0.9%	1.3%	1.0%	1.1%	0.5%	0.9%	0.8%	1.1%	0.5%	0.8%	
DPL	19,730	20,046	20,310	20,633	20,958	21,348	21,621	21,967	22,289	22,685	22,979	23,329	1.5%
%		1.6%	1.3%	1.6%	1.6%	1.9%	1.3%	1.6%	1.5%	1.8%	1.3%	1.5%	
JCPL	24,935	25,418	25,954	26,611	27,183	27,792	28,246	28,828	29,387	30,041	30,526	31,067	2.0%
%		1.9%	2.1%	2.5%	2.1%	2.2%	1.6%	2.1%	1.9%	2.2%	1.6%	1.8%	
METED	16,041	16,308	16,551	16,882	17,155	17,445	17,638	17,916	18,186	18,511	18,733	19,015	1.5%
%		1.7%	1.5%	2.0%	1.6%	1.7%	1.1%	1.6%	1.5%	1.8%	1.2%	1.5%	
PECO	41,768	42,514	43,179	43,972	44,670	45,446	45,973	46,677	47,353	48,162	48,702	49,353	1.5%
%		1.8%	1.6%	1.8%	1.6%	1.7%	1.2%	1.5%	1.4%	1.7%	1.1%	1.3%	
PENLC	18,400	18,667	18,908	19,224	19,477	19,757	19,926	20,182	20,413	20,696	20,836	21,034	1.2%
%		1.5%	1.3%	1.7%	1.3%	1.4%	0.9%	1.3%	1.1%	1.4%	0.7%	1.0%	
PEPCO	32,883	33,399	33,754	34,216	34,633	35,151	35,499	35,984	36,436	37,004	37,385	37,873	1.3%
%		1.6%	1.1%	1.4%	1.2%	1.5%	1.0%	1.4%	1.3%	1.6%	1.0%	1.3%	
PL	42,027	42,692	43,241	43,995	44,629	45,330	45,780	46,430	47,054	47,837	48,340	48,992	1.4%
%		1.6%	1.3%	1.7%	1.4%	1.6%	1.0%	1.4%	1.3%	1.7%	1.1%	1.3%	
PS	48,368	49,120	49,876	50,817	51,669	52,523	53,104	53,961	54,757	55,726	56,366	57,103	1.5%
%		1.6%	1.5%	1.9%	1.7%	1.7%	1.1%	1.6%	1.5%	1.8%	1.1%	1.3%	
RECO	1,556	1,570	1,584	1,600	1,615	1,630	1,638	1,654	1,669	1,688	1,695	1,706	0.8%
%		0.9%	0.9%	1.0%	0.9%	0.9%	0.5%	1.0%	0.9%	1.1%	0.4%	0.6%	
UGI	1,082	1,097	1,107	1,121	1,134	1,149	1,161	1,174	1,187	1,205	1,215	1,228	1.1%
%		1.4%	0.9%	1.3%	1.2%	1.3%	1.0%	1.1%	1.1%	1.5%	0.8%	1.1%	
PJM MID-ATLANTIC	293,514	298,261	302,476	307,893	312,930	318,302	322,003	326,933	331,437	336,964	340,614	345,093	1.5%
%		1.6%	1.4%	1.8%	1.6%	1.7%	1.2%	1.5%	1.4%	1.7%	1.1%	1.3%	
FE/GPU	59,376	60,393	61,413	62,717	63,815	64,994	65,810	66,926	67,986	69,248	70,095	71,116	1.6%
%		1.7%	1.7%	2.1%	1.8%	1.8%	1.3%	1.7%	1.6%	1.9%	1.2%	1.5%	
PLGRP	43,109	43,789	44,348	45,116	45,763	46,479	46,941	47,604	48,241	49,042	49,555	50,220	1.4%
%		1.6%	1.3%	1.7%	1.4%	1.6%	1.0%	1.4%	1.3%	1.7%	1.0%	1.3%	

Note: Values presented are consistent with Net Energy for Load, and may not be consistent with utility sales.

Table E-1 (Continued)

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR EACH PJM MID-ATLANTIC GEOGRAPHIC ZONE AND SUM OF GEOGRAPHIC ZONES 2019-2023

		2019	2020	2021	2022	2023	Annual Growth Rate (15 yr)
AE		15,980	16,262	16,475	16,732	16,999	2.3%
	%	1.5%	1.8%	1.3%	1.6%	1.6%	
BGE		38,935	39,357	39,553	39,876	40,189	0.9%
	%	0.7%	1.1%	0.5%	0.8%	0.8%	
DPL		23,681	24,142	24,461	24,863	25,275	1.6%
	%	1.5%	1.9%	1.3%	1.6%	1.7%	
JCPL		31,588	32,244	32,741	33,340	33,934	1.9%
	%	1.7%	2.1%	1.5%	1.8%	1.8%	
METED		19,276	19,649	19,893	20,201	20,494	1.5%
	%	1.4%	1.9%	1.2%	1.5%	1.5%	
PECO		49,981	50,812	51,350	52,053	52,739	1.4%
	%	1.3%	1.7%	1.1%	1.4%	1.3%	
PENLC		21,215	21,503	21,644	21,851	22,034	1.1%
	%	0.9%	1.4%	0.7%	1.0%	0.8%	
PEPCO		38,321	38,901	39,263	39,772	40,268	1.3%
	%	1.2%	1.5%	0.9%	1.3%	1.2%	
PL		49,610	50,469	51,009	51,722	52,394	1.4%
	%	1.3%	1.7%	1.1%	1.4%	1.3%	
PS		57,804	58,808	59,456	60,315	61,123	1.5%
	%	1.2%	1.7%	1.1%	1.4%	1.3%	
RECO		1,718	1,737	1,750	1,763	1,773	0.8%
	%	0.7%	1.1%	0.7%	0.7%	0.6%	
UGI		1,242	1,260	1,269	1,286	1,299	1.1%
	%	1.1%	1.4%	0.7%	1.3%	1.0%	
PJM MID-ATLANTIC		349,351	355,144	358,864	363,774	368,521	1.4%
	%	1.2%	1.7%	1.0%	1.4%	1.3%	
FE/GPU		72,079	73,396	74,278	75,392	76,462	1.6%
	%	1.4%	1.8%	1.2%	1.5%	1.4%	
PLGRP		50,852	51,729	52,278	53,008	53,693	1.4%
	%	1.3%	1.7%	1.1%	1.4%	1.3%	

Note: Values presented are consistent with Net Energy for Load, and may not be consistent with utility sales.

Table E-1

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR
EACH PJM WESTERN AND PJM SOUTHERN GEOGRAPHIC ZONE AND SUM OF GEOGRAPHIC ZONES
2008-2018

		ESTIMATED 2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Annual Growth Rate (10 yr)
AEP		139,765	141,365	142,780	144,726	146,324	148,241	149,128	150,780	152,253	154,164	155,098	156,355	1.0%
	%		1.1%	1.0%	1.4%	1.1%	1.3%	0.6%	1.1%	1.0%	1.3%	0.6%	0.8%	
APS		51,040	51,432	51,651	52,070	52,438	52,924	53,083	53,474	53,791	54,251	54,403	54,706	0.6%
	%		0.8%	0.4%	0.8%	0.7%	0.9%	0.3%	0.7%	0.6%	0.9%	0.3%	0.6%	
COMED		106,078	108,516	111,033	113,691	116,097	118,766	120,865	123,587	126,233	129,223	131,432	133,895	2.1%
	%		2.3%	2.3%	2.4%	2.1%	2.3%	1.8%	2.3%	2.1%	2.4%	1.7%	1.9%	
DAY		18,933	19,117	19,319	19,594	19,802	20,052	20,170	20,402	20,604	20,858	20,977	21,126	1.0%
	%		1.0%	1.1%	1.4%	1.1%	1.3%	0.6%	1.2%	1.0%	1.2%	0.6%	0.7%	
DLCO		14,877	15,003	15,124	15,304	15,461	15,648	15,741	15,903	16,047	16,239	16,337	16,477	0.9%
	%		0.8%	0.8%	1.2%	1.0%	1.2%	0.6%	1.0%	0.9%	1.2%	0.6%	0.9%	
PJM WESTERN		330,693	335,433	339,907	345,385	350,122	355,631	358,987	364,146	368,928	374,735	378,247	382,559	1.3%
	%		1.4%	1.3%	1.6%	1.4%	1.6%	0.9%	1.4%	1.3%	1.6%	0.9%	1.1%	
DOM		94,493	96,125	97,665	99,936	101,733	103,819	105,312	107,228	109,032	111,230	112,745	114,353	1.8%
	%		1.7%	1.6%	2.3%	1.8%	2.1%	1.4%	1.8%	1.7%	2.0%	1.4%	1.4%	
PJM RTO		718,700	729,819	740,048	753,214	764,785	777,752	786,302	798,307	809,397	822,929	831,606	842,005	1.4%
	%		1.5%	1.4%	1.8%	1.5%	1.7%	1.1%	1.5%	1.4%	1.7%	1.1%	1.3%	

Note: Values presented are consistent with Net Energy for Load, and may not be consistent with utility sales.

Table E-1 (Continued)

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR
EACH PJM WESTERN AND PJM SOUTHERN GEOGRAPHIC ZONE AND SUM OF GEOGRAPHIC ZONES
2019-2023

		2019	2020	2021	2022	2023	Annual Growth Rate (15 yr)
AEP		157,324	159,130	159,844	161,063	162,132	0.9%
	%	0.6%	1.1%	0.4%	0.8%	0.7%	
APS		54,952	55,469	55,595	55,906	56,183	0.6%
	%	0.4%	0.9%	0.2%	0.6%	0.5%	
COMED		136,117	138,980	141,049	143,607	146,134	2.0%
	%	1.7%	2.1%	1.5%	1.8%	1.8%	
DAY		21,258	21,515	21,614	21,776	21,912	0.9%
	%	0.6%	1.2%	0.5%	0.7%	0.6%	
DLCO		16,593	16,789	16,887	17,035	17,172	0.9%
	%	0.7%	1.2%	0.6%	0.9%	0.8%	
PJM WESTERN		386,244	391,883	394,989	399,387	403,533	1.2%
	%	1.0%	1.5%	0.8%	1.1%	1.0%	
DOM		115,839	117,697	118,810	120,370	121,927	1.6%
	%	1.3%	1.6%	0.9%	1.3%	1.3%	
PJM RTO		851,434	864,724	872,663	883,531	893,981	1.4%
	%	1.1%	1.6%	0.9%	1.2%	1.2%	

Note: Values presented are consistent with Net Energy for Load, and may not be consistent with utility sales.

Table E-2

**MONTHLY NET ENERGY FORECAST (GWh) FOR EACH
PJM MID-ATLANTIC GEOGRAPHIC ZONE AND SUM OF GEOGRAPHIC ZONES**

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	PJM MID-ATLANTIC
Jan 2008	1,014	3,276	1,840	2,180	1,480	3,741	1,697	2,950	4,057	4,112	128	109	26,584
Feb 2008	928	2,954	1,685	1,982	1,357	3,414	1,567	2,680	3,694	3,778	116	98	24,253
Mar 2008	917	2,839	1,604	1,985	1,353	3,399	1,585	2,581	3,622	3,846	120	95	23,946
Apr 2008	856	2,515	1,426	1,832	1,239	3,138	1,459	2,366	3,239	3,631	114	82	21,897
May 2008	908	2,608	1,477	1,922	1,276	3,264	1,495	2,499	3,295	3,816	123	82	22,765
Jun 2008	1,050	3,050	1,697	2,231	1,341	3,635	1,481	3,027	3,379	4,344	144	83	25,462
Jul 2008	1,314	3,534	2,004	2,692	1,497	4,233	1,589	3,463	3,765	5,068	171	95	29,425
Aug 2008	1,288	3,445	1,966	2,581	1,475	4,109	1,592	3,345	3,702	4,902	162	92	28,659
Sep 2008	981	2,781	1,561	2,005	1,262	3,347	1,484	2,732	3,288	3,969	124	81	23,615
Oct 2008	918	2,606	1,496	1,947	1,305	3,322	1,548	2,476	3,366	3,861	122	85	23,052
Nov 2008	896	2,638	1,519	1,910	1,279	3,257	1,508	2,450	3,380	3,738	118	89	22,782
Dec 2008	1,009	3,105	1,771	2,151	1,444	3,655	1,662	2,830	3,905	4,055	128	106	25,821

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	MID-ATLANTIC
Jan 2009	1,033	3,291	1,860	2,213	1,494	3,786	1,712	2,971	4,089	4,153	129	109	26,840
Feb 2009	914	2,879	1,652	1,948	1,329	3,350	1,533	2,621	3,612	3,699	113	96	23,746
Mar 2009	940	2,872	1,632	2,032	1,385	3,475	1,618	2,620	3,697	3,929	122	96	24,418
Apr 2009	879	2,545	1,448	1,875	1,256	3,194	1,477	2,397	3,280	3,694	115	83	22,243
May 2009	931	2,636	1,499	1,966	1,295	3,323	1,514	2,529	3,339	3,879	124	83	23,118
Jun 2009	1,076	3,093	1,726	2,286	1,368	3,712	1,505	3,072	3,444	4,429	146	85	25,942
Jul 2009	1,344	3,579	2,036	2,756	1,522	4,308	1,614	3,509	3,825	5,157	173	96	29,919
Aug 2009	1,317	3,490	1,998	2,645	1,501	4,186	1,616	3,391	3,763	4,991	164	93	29,155
Sep 2009	1,006	2,811	1,585	2,055	1,284	3,404	1,508	2,763	3,341	4,035	125	82	23,999
Oct 2009	945	2,642	1,520	2,000	1,328	3,383	1,571	2,511	3,418	3,936	123	86	23,463
Nov 2009	922	2,680	1,548	1,966	1,308	3,326	1,540	2,493	3,449	3,819	120	91	23,262
Dec 2009	1,035	3,152	1,806	2,212	1,481	3,732	1,700	2,877	3,984	4,155	130	107	26,371

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	MID-ATLANTIC
Jan 2010	1,056	3,325	1,887	2,262	1,520	3,843	1,739	3,008	4,144	4,225	130	110	27,249
Feb 2010	937	2,916	1,679	1,995	1,355	3,409	1,559	2,660	3,670	3,770	114	97	24,161
Mar 2010	973	2,925	1,670	2,097	1,419	3,556	1,653	2,676	3,778	4,023	123	98	24,991
Apr 2010	906	2,581	1,472	1,927	1,280	3,256	1,500	2,432	3,337	3,766	116	84	22,657
May 2010	961	2,674	1,523	2,021	1,323	3,391	1,542	2,567	3,404	3,958	126	84	23,574
Jun 2010	1,107	3,138	1,754	2,348	1,397	3,785	1,532	3,114	3,513	4,517	148	86	26,439
Jul 2010	1,377	3,617	2,060	2,816	1,547	4,368	1,632	3,543	3,877	5,232	174	97	30,340
Aug 2010	1,352	3,544	2,032	2,716	1,539	4,274	1,652	3,443	3,847	5,097	167	95	29,758
Sep 2010	1,035	2,849	1,610	2,109	1,310	3,469	1,533	2,799	3,401	4,111	126	83	24,435
Oct 2010	972	2,670	1,541	2,046	1,349	3,439	1,591	2,538	3,465	4,000	124	87	23,822
Nov 2010	944	2,713	1,571	2,012	1,338	3,389	1,567	2,523	3,519	3,890	121	92	23,679
Dec 2010	1,062	3,188	1,834	2,262	1,505	3,793	1,724	2,913	4,040	4,228	131	108	26,788

Table E-2

MONTHLY NET ENERGY FORECAST (GWh) FOR EACH
PJM WESTERN AND PJM SOUTHERN GEOGRAPHIC ZONE AND SUM OF GEOGRAPHIC ZONES

	AEP	**APS**	**COMED**	**DAY**	**DLCO**	**PJM WESTERN**	**DOM**	**PJM RTO**
Jan 2008	13,159	4,875	9,333	1,700	1,291	30,358	8,934	65,876
Feb 2008	11,975	4,453	8,586	1,549	1,187	27,750	8,039	60,042
Mar 2008	11,788	4,335	8,628	1,547	1,209	27,507	7,615	59,068
Apr 2008	10,741	3,900	8,147	1,446	1,135	25,369	6,791	54,057
May 2008	11,074	3,979	8,485	1,501	1,198	26,237	7,127	56,129
Jun 2008	11,499	4,093	9,113	1,612	1,280	27,597	8,406	61,465
Jul 2008	12,671	4,507	10,721	1,810	1,454	31,163	9,503	70,091
Aug 2008	12,536	4,468	10,329	1,778	1,415	30,526	9,241	68,426
Sep 2008	10,920	3,945	8,634	1,504	1,204	26,207	7,635	57,457
Oct 2008	11,204	4,049	8,675	1,523	1,199	26,650	7,109	56,811
Nov 2008	11,127	4,102	8,489	1,490	1,163	26,371	7,202	56,355
Dec 2008	12,671	4,726	9,376	1,657	1,268	29,698	8,523	64,042
	AEP	**APS**	**COMED**	**DAY**	**DLCO**	**WESTERN**	**DOM**	**PJM RTO**
Jan 2009	13,226	4,886	9,505	1,708	1,296	30,621	9,027	66,488
Feb 2009	11,678	4,328	8,472	1,510	1,155	27,143	7,887	58,776
Mar 2009	11,991	4,380	8,891	1,577	1,226	28,065	7,749	60,232
Apr 2009	10,853	3,920	8,350	1,462	1,145	25,730	6,914	54,887
May 2009	11,183	3,994	8,702	1,516	1,208	26,603	7,243	56,964
Jun 2009	11,665	4,129	9,387	1,638	1,296	28,115	8,564	62,621
Jul 2009	12,838	4,537	10,986	1,833	1,471	31,665	9,686	71,270
Aug 2009	12,702	4,498	10,593	1,801	1,431	31,025	9,424	69,604
Sep 2009	11,057	3,968	8,858	1,524	1,216	26,623	7,773	58,395
Oct 2009	11,347	4,072	8,901	1,542	1,212	27,074	7,274	57,811
Nov 2009	11,321	4,149	8,734	1,517	1,180	26,901	7,390	57,553
Dec 2009	12,919	4,790	9,654	1,691	1,288	30,342	8,734	65,447
	AEP	**APS**	**COMED**	**DAY**	**DLCO**	**WESTERN**	**DOM**	**PJM RTO**
Jan 2010	13,385	4,925	9,719	1,729	1,308	31,066	9,224	67,539
Feb 2010	11,845	4,370	8,680	1,532	1,168	27,595	8,075	59,831
Mar 2010	12,209	4,449	9,160	1,609	1,245	28,672	7,977	61,640
Apr 2010	10,997	3,949	8,562	1,482	1,158	26,148	7,094	55,899
May 2010	11,349	4,027	8,929	1,541	1,224	27,070	7,431	58,075
Jun 2010	11,840	4,163	9,633	1,664	1,313	28,613	8,770	63,822
Jul 2010	12,960	4,551	11,211	1,846	1,483	32,051	9,877	72,268
Aug 2010	12,913	4,547	10,861	1,835	1,454	31,610	9,652	71,020
Sep 2010	11,207	3,997	9,075	1,546	1,231	27,056	7,952	59,443
Oct 2010	11,456	4,089	9,090	1,558	1,224	27,417	7,415	58,654
Nov 2010	11,515	4,181	8,924	1,546	1,195	27,361	7,558	58,598
Dec 2010	13,050	4,822	9,847	1,706	1,301	30,726	8,911	66,425

Table E-3

MONTHLY NET ENERGY FORECAST (GWh)
FOR FE/GPU AND PLGRP

	FE/GPU	PLGRP
Jan 2008	5,357	4,166
Feb 2008	4,906	3,792
Mar 2008	4,923	3,717
Apr 2008	4,530	3,321
May 2008	4,693	3,377
Jun 2008	5,053	3,462
Jul 2008	5,778	3,860
Aug 2008	5,648	3,794
Sep 2008	4,751	3,369
Oct 2008	4,800	3,451
Nov 2008	4,697	3,469
Dec 2008	5,257	4,011

	FE/GPU	PLGRP
Jan 2009	5,419	4,198
Feb 2009	4,810	3,708
Mar 2009	5,035	3,793
Apr 2009	4,608	3,363
May 2009	4,775	3,422
Jun 2009	5,159	3,529
Jul 2009	5,892	3,921
Aug 2009	5,762	3,856
Sep 2009	4,847	3,423
Oct 2009	4,899	3,504
Nov 2009	4,814	3,540
Dec 2009	5,393	4,091

	FE/GPU	PLGRP
Jan 2010	5,521	4,254
Feb 2010	4,909	3,767
Mar 2010	5,169	3,876
Apr 2010	4,707	3,421
May 2010	4,886	3,488
Jun 2010	5,277	3,599
Jul 2010	5,995	3,974
Aug 2010	5,907	3,942
Sep 2010	4,952	3,484
Oct 2010	4,986	3,552
Nov 2010	4,917	3,611
Dec 2010	5,491	4,148

TABLE F-1

PJM RTO HISTORICAL PEAKS
(MW)

SUMMER

YEAR	NORMALIZED BASE	NORMALIZED COOLING	NORMALIZED TOTAL	UNRESTRICTED PEAK	PEAK DATE/TIME
1998	72,950	38,170	111,120	114,996	07/21/1998 17:00
1999	73,990	42,980	116,970	121,655	07/06/1999 17:00
2000	76,300	40,080	116,380	114,178	08/09/2000 17:00
2001	75,990	45,080	121,070	131,116	08/09/2001 16:00
2002	77,140	48,120	125,260	130,360	08/01/2002 17:00
2003	77,650	46,700	124,350	126,332	08/21/2003 17:00
2004			130,645	120,235	06/09/2004 17:00
2005			133,550	134,219	07/26/2005 16:00
2006			134,905	145,951	08/02/2006 17:00
2007			136,095	141,383	08/08/2007 17:00

WINTER

YEAR	NORMALIZED BASE	NORMALIZED HEATING	NORMALIZED TOTAL	UNRESTRICTED PEAK	PEAK DATE/TIME
97/98				88,970	01/14/1998 19:00
98/99				99,982	01/05/1999 19:00
99/00				102,359	01/27/2000 20:00
00/01				101,717	12/20/2000 19:00
01/02				97,294	01/03/2002 19:00
02/03				112,755	01/23/2003 19:00
03/04			108,110	106,760	01/26/2004 19:00
04/05			110,250	114,061	12/20/2004 19:00
05/06			111,745	110,415	12/14/2005 19:00
06/07			112,455	118,800	02/05/2007 20:00

Notes: Normalized values for 1998 - 2003 are calculated by PJM staff using the bottom-up coincident peak weather-normalization methodology.
Normalized values for 2004 - 2007 are calculated by PJM staff using a methodology consistent with the PJM Load Forecast Model.

TABLE F-2

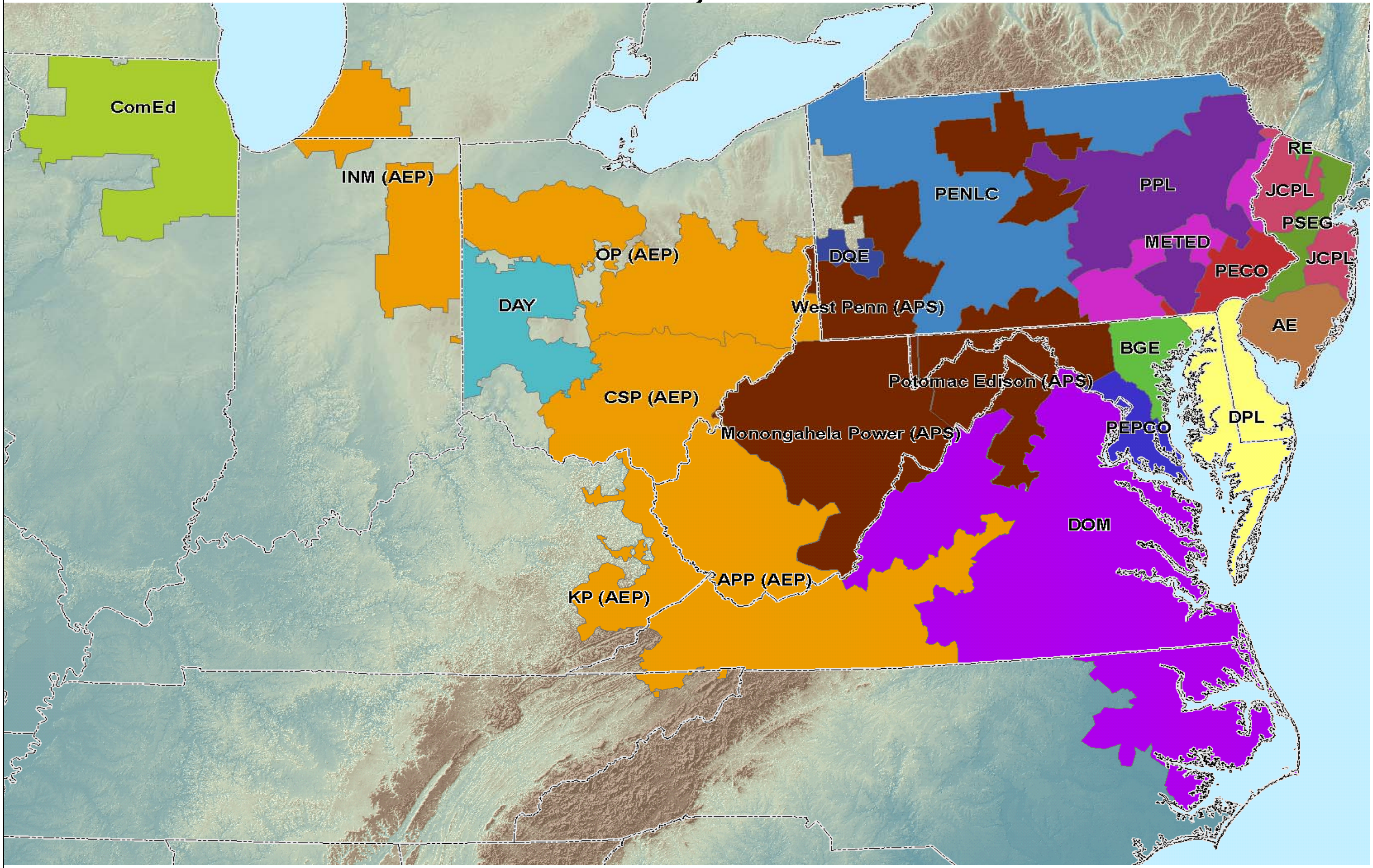
PJM RTO HISTORICAL NET ENERGY
(GWH)

YEAR	ENERGY	GROWTH RATE
1998	620,061	0.8%
1999	636,404	2.6%
2000	651,190	2.3%
2001	651,319	0.0%
2002	673,526	3.4%
2003	674,471	0.1%
2004	689,008	2.2%
2005	682,441	-1.0%
2006	694,989	1.8%

Note: All historic net energy values reflect the membership of the PJM RTO as of December 31, 2007.

Exhibit RMF-4

PJM Load Forecast Report
January 2009



Prepared by PJM Capacity Adequacy Planning Department

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TERMS AND ABBREVIATIONS USED IN THIS REPORT

AE	Atlantic Electric zone (part of Pepco Holdings, Inc)
AEP	American Electric Power zone (incorporated 10/1/2004)
APP	Appalachian Power, sub-zone of AEP
APS	Allegheny Power zone (incorporated 4/1/2002)
Base Load	Average peak load on non-holiday weekdays with no heating or cooling load. Base load is insensitive to weather.
BGE	Baltimore Gas & Electric zone
COMED	Commonwealth Edison zone (incorporated 5/1/2004)
Contractually Interruptible	Load Management from customers responding to direction from a control center
Cooling Load	The weather-sensitive portion of summer peak load
CSP	Columbus Southern Power, sub-zone of AEP
Direct Control	Load Management achieved directly by a signal from a control center
DAY	Dayton Power & Light zone (incorporated 10/1/2004)
DLCO	Duquesne Lighting Company zone (incorporated 1/1/2005)
DPL	Delmarva Power & Light zone (part of Pepco Holdings, Inc)
FE/GPU	The combination of FirstEnergy's Jersey Central Power & Light, Metropolitan Edison, and Pennsylvania Electric zones (formerly GPU)
Heating Load	The weather-sensitive portion of winter peak load
INM	Indiana Michigan Power, sub-zone of AEP
JCPL	Jersey Central Power & Light zone
KP	Kentucky Power, sub-zone of AEP
METED	Metropolitan Edison zone
MP	Monongahela Power, sub-zone of APS
Net Energy	Net Energy for Load, measured as net generation of main generating units plus energy receipts minus energy deliveries
OP	Ohio Power, sub-zone of AEP
PECO	PECO Energy zone

PED	Potomac Edison, sub-zone of APS
PEPCO	Potomac Electric Power zone (part of Pepco Holdings, Inc)
PL	PPL Electric Utilities, sub-zone of PLGroup
PLGroup/PLGRP	Pennsylvania Power & Light zone
PENLC	Pennsylvania Electric zone
PS	Public Service Electric & Gas zone
RECO	Rockland Electric (East) zone (incorporated 3/1/2002)
UGI	UGI Utilities, sub-zone of PLGroup
WP	West Penn Power, sub-zone of APS
Zone	Areas within the PJM Control Area, as defined in the PJM Reliability Assurance Agreement

2009 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 and load management for each PJM zone, region, and the total RTO.

- Several new tables appear in this year's report:
  - Table B-8 presents the projected impact of energy efficiency (EE) programs which have cleared in Reliability Pricing Model (RPM) auctions, and will be used in the PJM planning process (the impacts will be removed once the EE is in place and reflected in the metered load);
  - Table B-9 presents adjustments made to the load forecast model by PJM staff to account for large load shifts deemed to not be captured in the forecast model; and
  - Table G-1 presents five-, ten- and fifteen-year average growth rates of Gross Metropolitan Product for each zone and the total RTO.

- The Load Management assumptions shown in Table B-7 are now derived by using the summation of the amount of Demand Resources cleared in RPM auctions plus the five-year average of Interruptible Load for Reliability. The assumptions vary for the first three years of the forecast then remain constant.

- The PJM RTO weather normalized summer peak for 2008 was 136,315 MW. The projection for the 2009 PJM RTO summer peak is 134,428 MW, a decrease of 1,887 MW, or 1.4%, from the 2008 normalized peak. An economic recession, as forecasted by Moody's Economy.com, will lead a majority of PJM zones to experience negative load growth from 2008 to 2009.

- An economic rebound in 2010 causes load growth to resume in 2010, though summer peak load will not exceed the 2008 level until 2011. Summer peak load growth for PJM RTO is projected to average 1.7% per year over the next 10 years, and 1.4% over the next 15 years. The PJM RTO summer peak is forecasted to be 158,617 MW in 2019, a 10-year increase of 24,189 MW, and reaches 166,581 MW in 2024, a 15-year increase of 32,153 MW. Annualized 10-year growth rates for individual zones range from 0.9% to 2.8%.

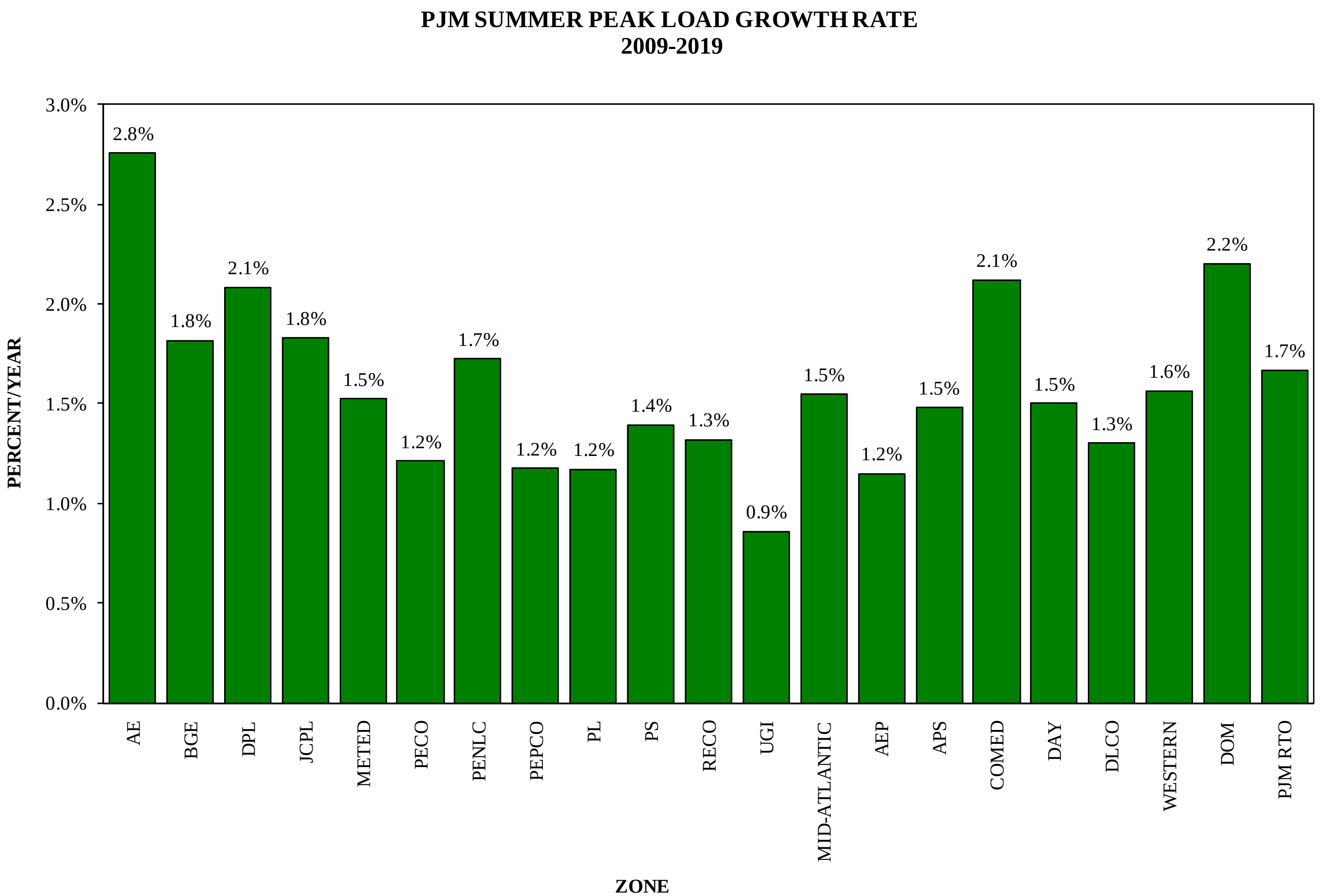
- Winter peak load growth for PJM RTO is projected to average 1.2% per year over the next 10-year period, and 1.1% over the next 15-years. The PJM RTO winter peak load in 2018/19 is forecasted to be 127,440 MW, a 10-year increase of 14,877 MW, and reaches 132,599 MW in 2023/24, a 15-year increase of 20,036 MW. Annualized 10-year growth rates for individual zones range from 0.5 to 2.4%.

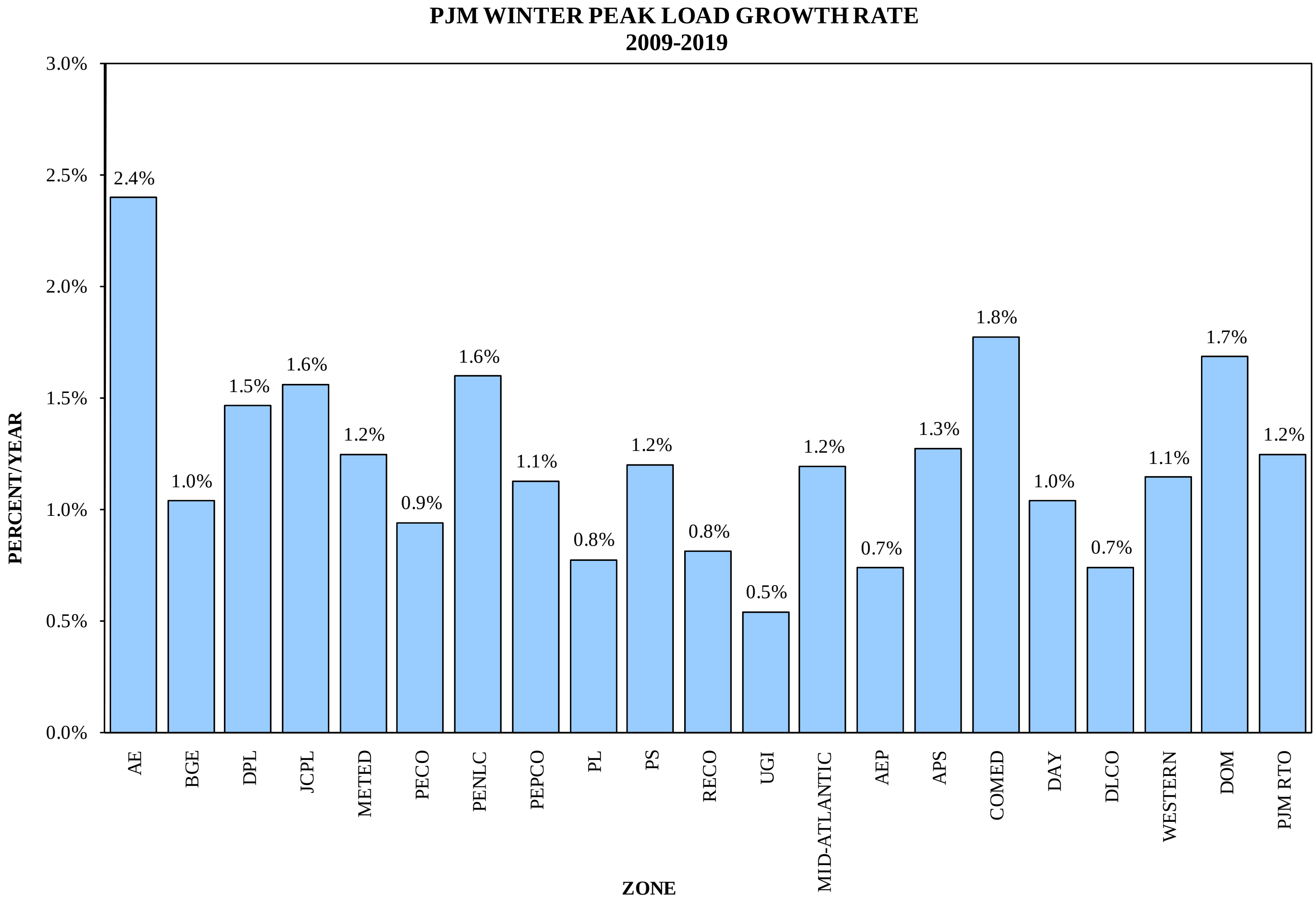
- Compared to the 2008 Load Report, the new forecast shows the following changes for three years of interest:
    - The next delivery year – 2009 -5,979 MW (4.3%)
    - The next RPM auction year – 2012 -2,570 MW (1.7%)
    - The next RTEP study year – 2014 -2,178 MW (1.4%)

- Several zones have notably different load growth patterns compared to the 2008 Load Report. Two zones have a different economic outlook: BGE zone is expected to have accelerated load growth as a result of the U.S. military's Base Realignment and Closure program, while PENLC zone's economic outlook is bolstered by revisions to the Erie and Altoona, PA forecasts to make them more consistent with their long-term historical Gross Metropolitan Product growth rate. The growth outlook for two zones (AEP and APS) has been impacted by an enhancement to PJM's forecast model to account for large historical load shifts.

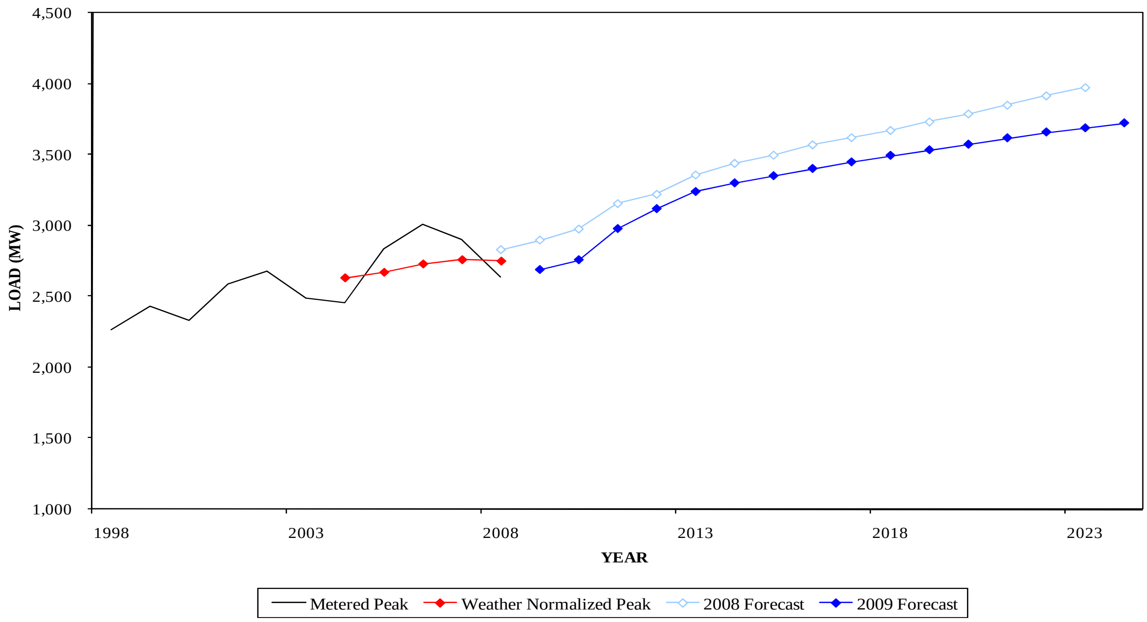
- Based on the forecast contained within this report, the PJM RTO will continue to be summer peaking during the next 15 years.

NOTE:
All compound growth rates are calculated from the first year of the forecast.

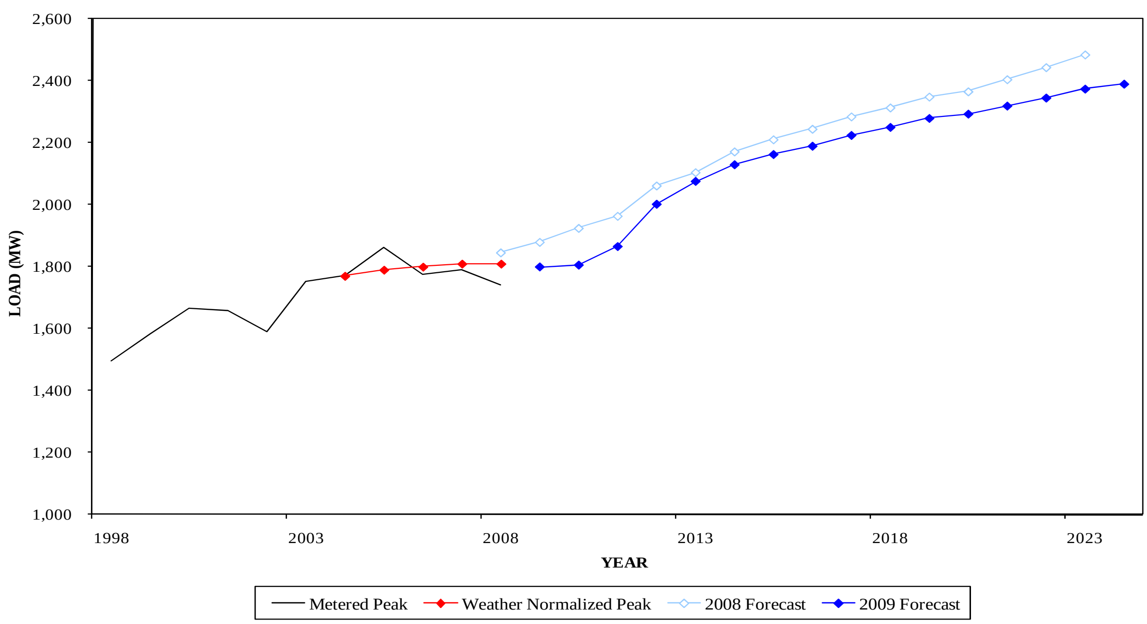

PJM SUMMER PEAK LOAD GROWTH RATE
2009-2019
PERCENT/YEAR
3.0%
2.5%
2.0%
1.5%
1.0%
0.5%
0.0%
2.8%
1.8%
2.1%
1.8%
1.5%
1.2%
1.7%
1.2%
1.2%
1.4%
1.3%
0.9%
1.5%
1.2%
1.5%
2.1%
1.5%
1.3%
1.6%
2.2%
1.7%
AE
BGE
DPL
JCPL
METED
PECO
PENLC
PEPCO
PL
PS
RECO
UGI
MID-ATLANTIC
AEP
APS
COMED
DAY
DLCO
WESTERN
DOM
PJM RTO
ZONE


PJM WINTER PEAK LOAD GROWTH RATE
2009-2019
PERCENT/YEAR
3.0%
2.5%
2.0%
1.5%
1.0%
0.5%
0.0%
2.4%
1.0%
1.5%
1.6%
1.2%
0.9%
1.6%
1.1%
0.8%
1.2%
0.8%
0.5%
1.2%
0.7%
1.3%
1.8%
1.0%
0.7%
1.1%
1.7%
1.2%
AE
BGE
DPL
JCPL
METED
PECO
PENLC
PEPCO
PL
PS
RECO
UGI
MID-ATLANTIC
AEP
APS
COMED
DAY
DLCO
WESTERN
DOM
PJM RTO
ZONE

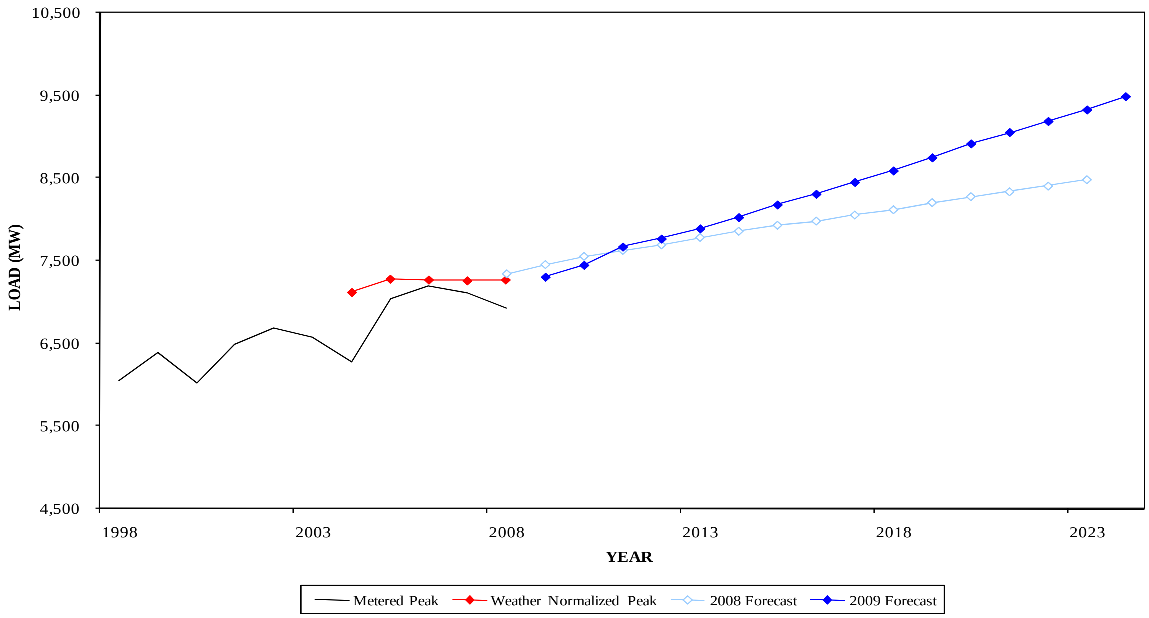
SUMMER PEAK DEMAND FOR AE GEOGRAPHIC ZONE



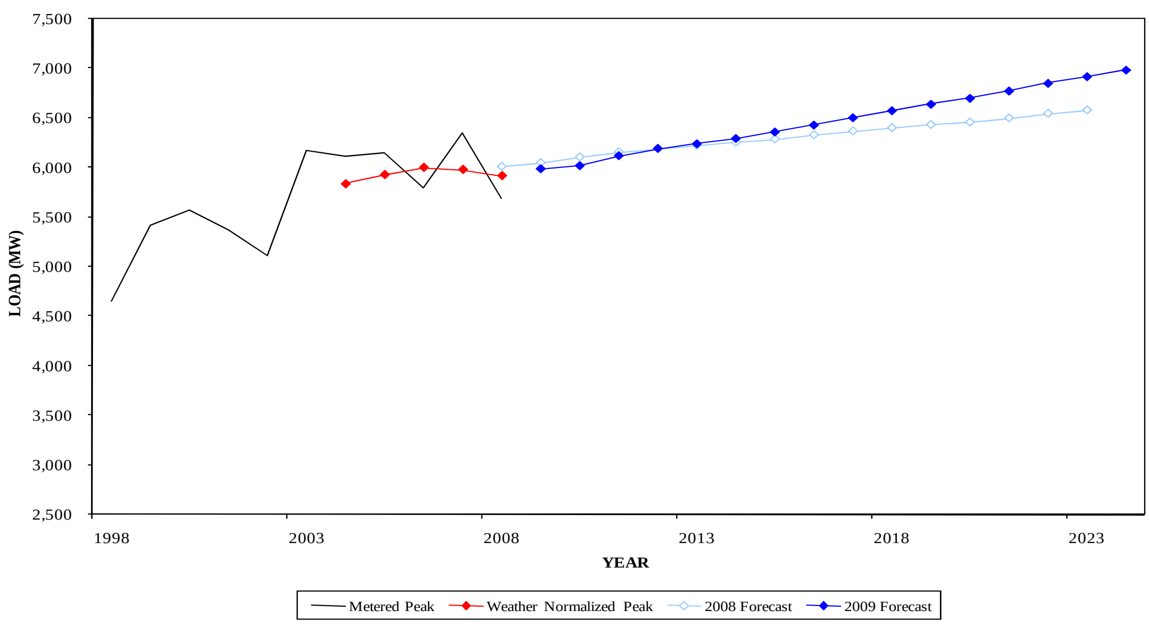
WINTER PEAK DEMAND FOR AE GEOGRAPHIC ZONE



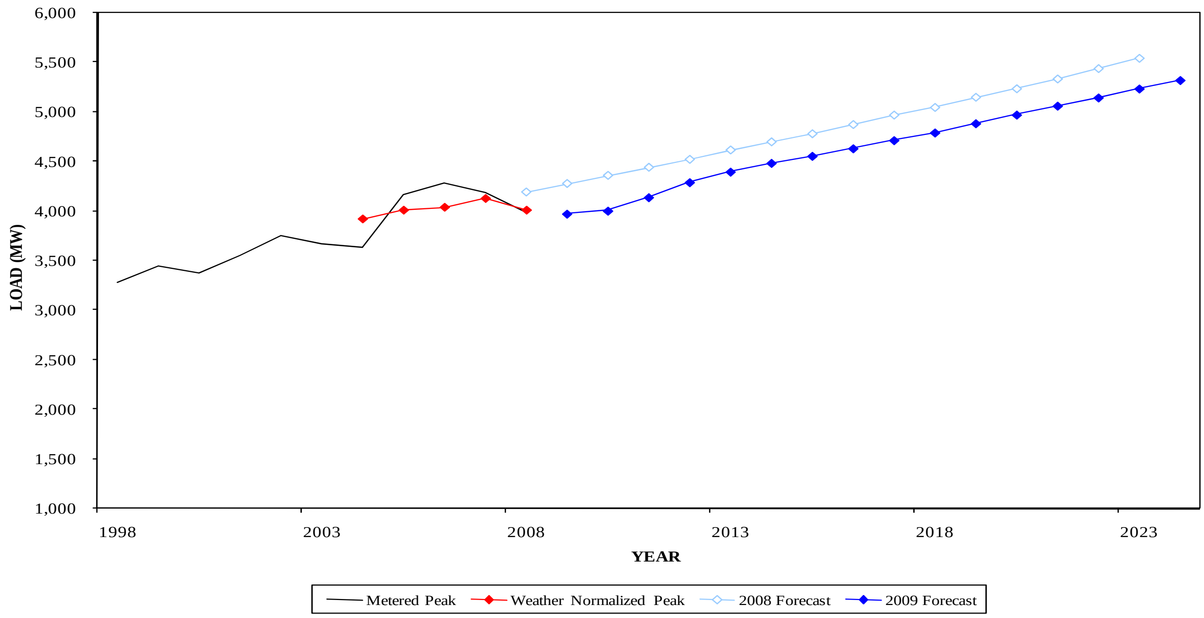
**SUMMER PEAK DEMAND FOR BGE
GEOGRAPHIC ZONE**



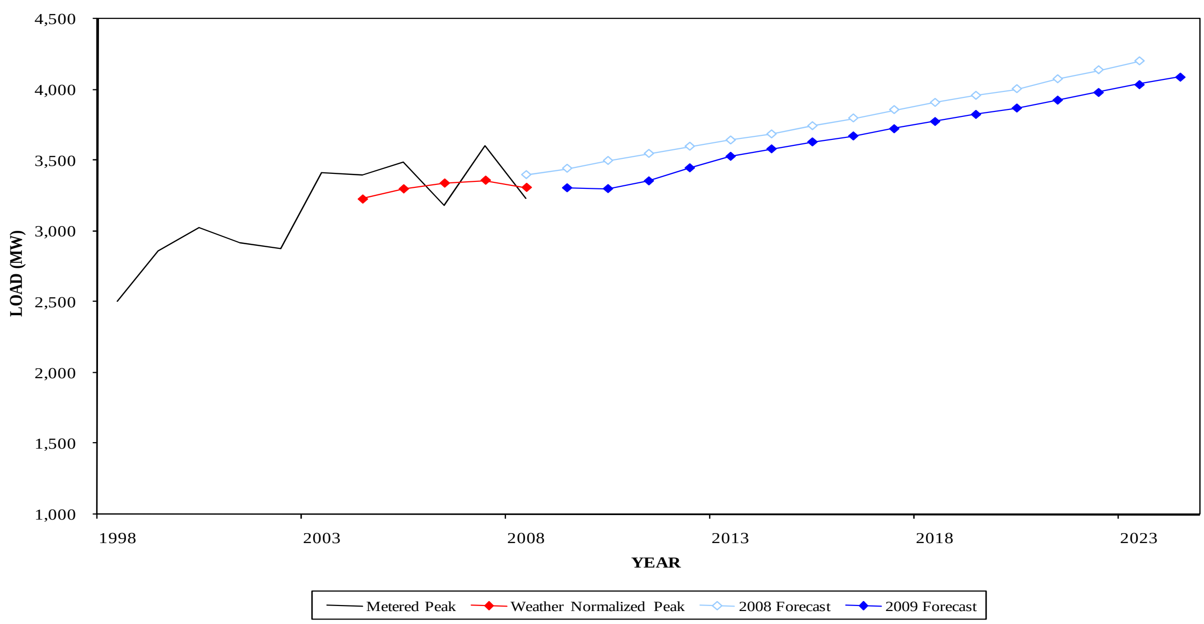
**WINTER PEAK DEMAND FOR BGE
GEOGRAPHIC ZONE**



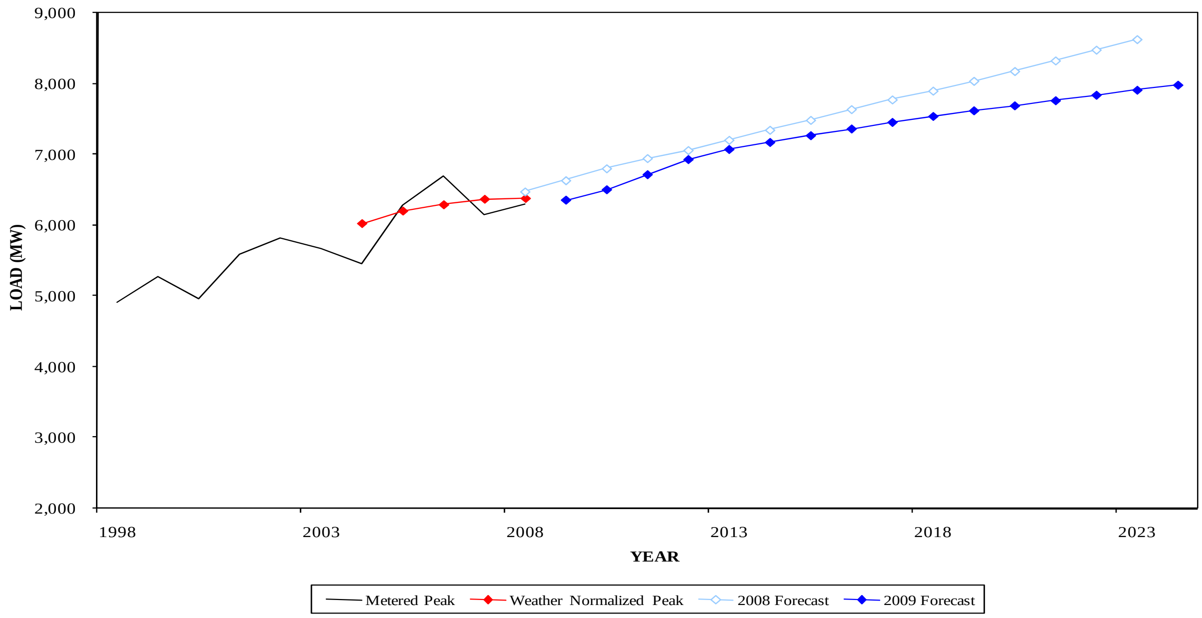
SUMMER PEAK DEMAND FOR DPL GEOGRAPHIC ZONE



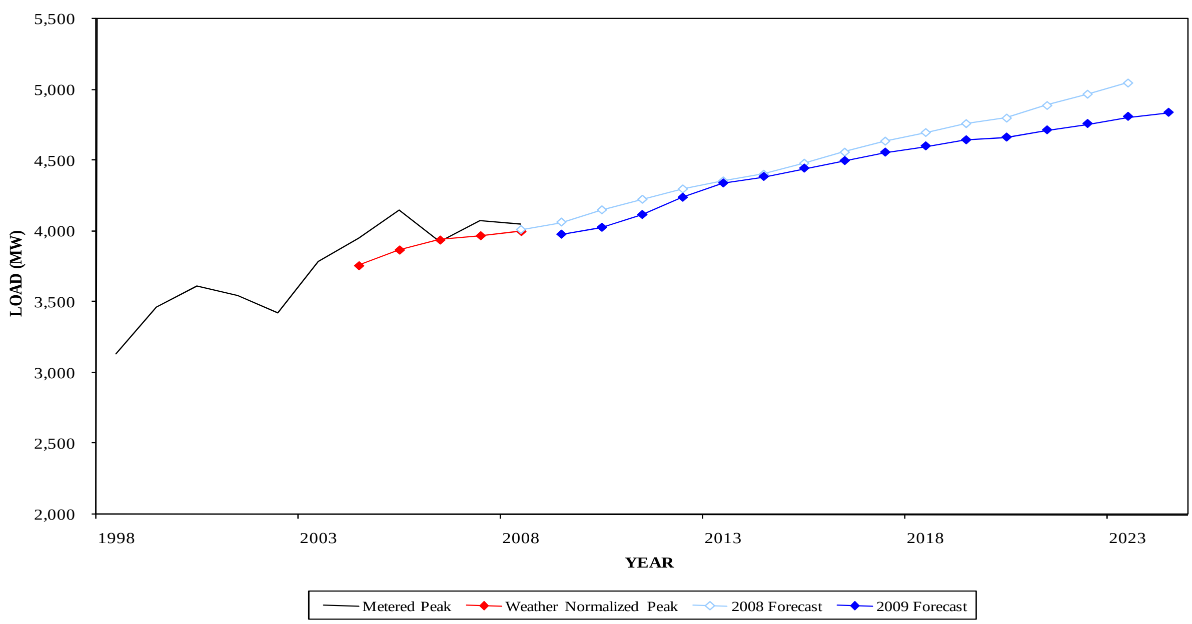
WINTER PEAK DEMAND FOR DPL GEOGRAPHIC ZONE



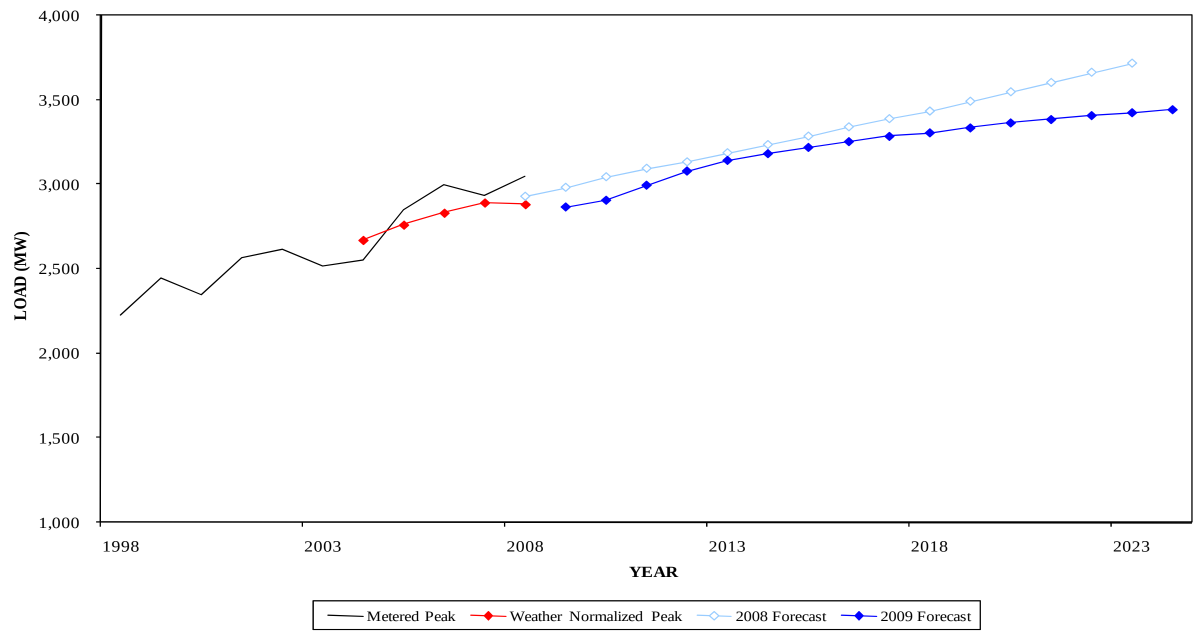
SUMMER PEAK DEMAND FOR JCPL GEOGRAPHIC ZONE



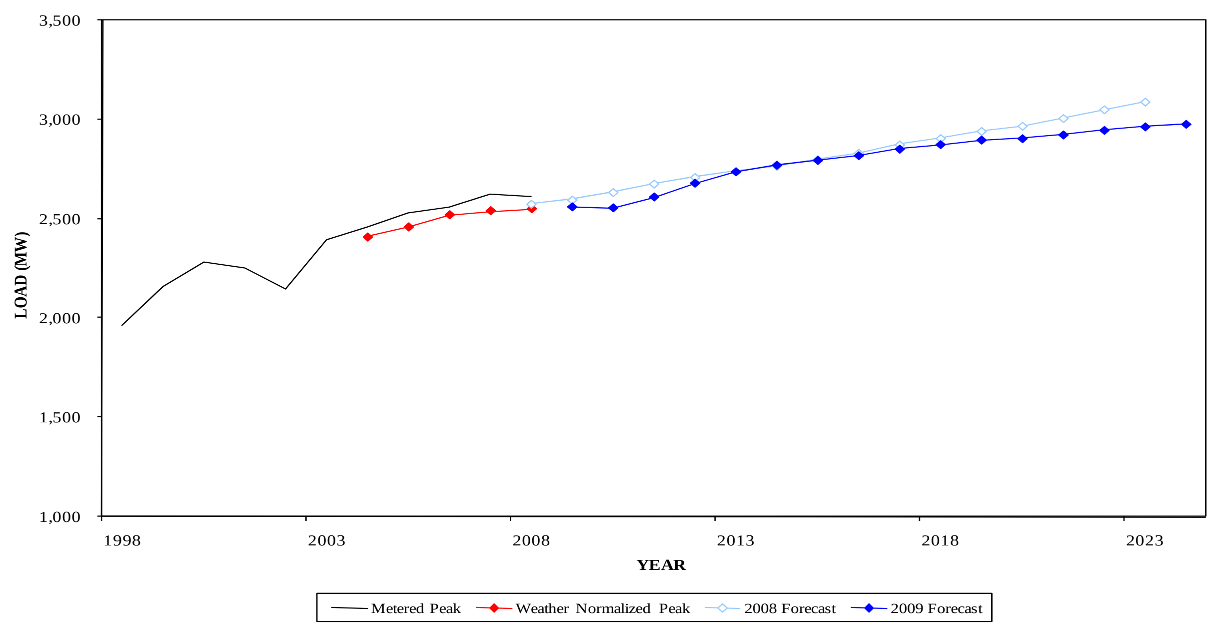
WINTER PEAK DEMAND FOR JCPL GEOGRAPHIC ZONE



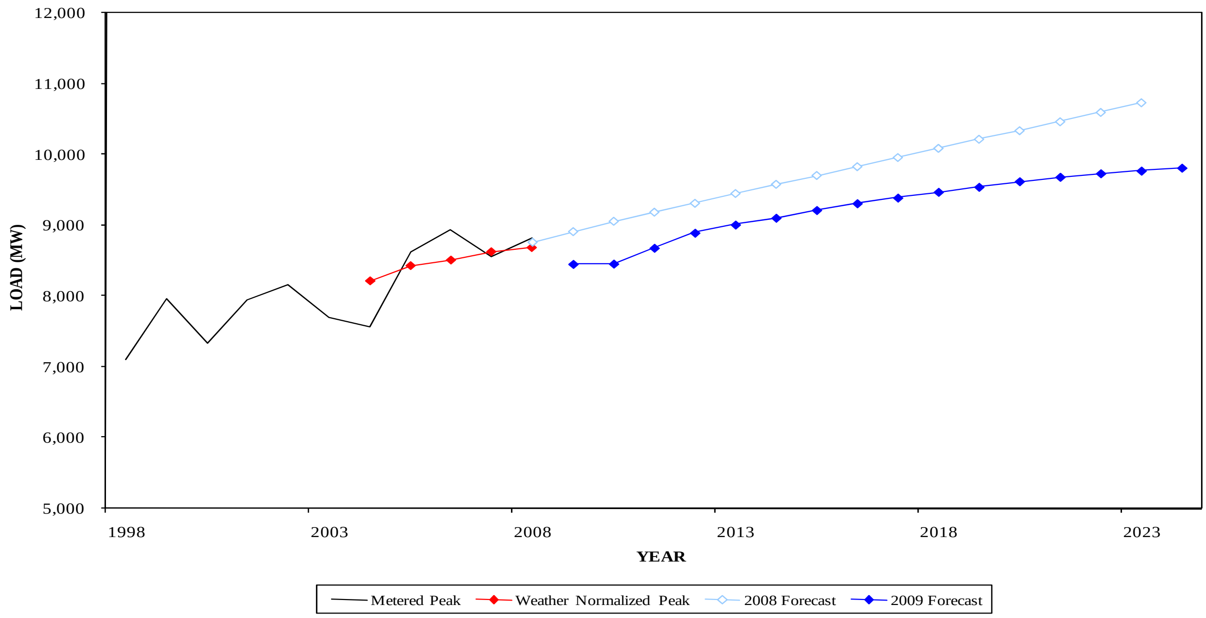
SUMMER PEAK DEMAND FOR METED GEOGRAPHIC ZONE



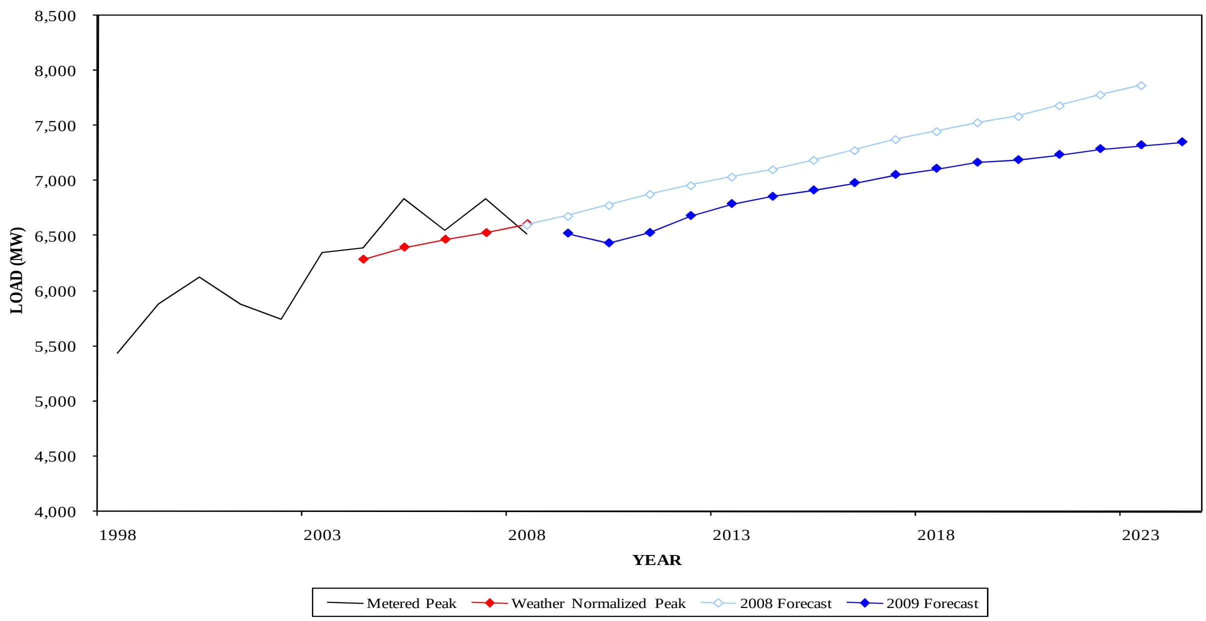
WINTER PEAK DEMAND FOR METED GEOGRAPHIC ZONE



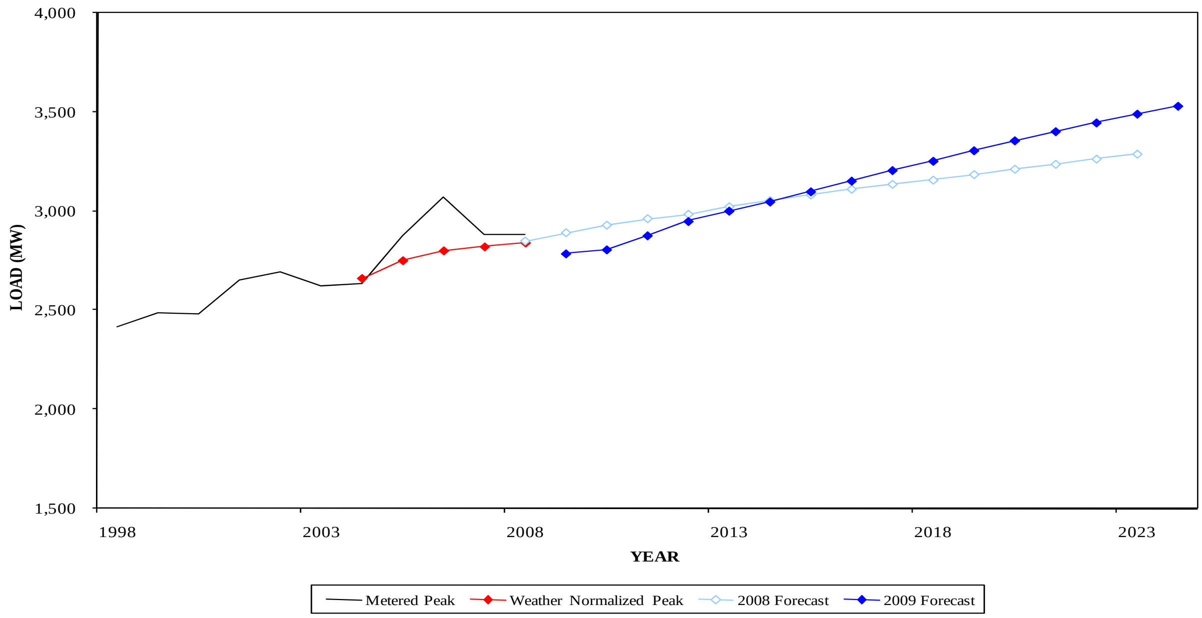
SUMMER PEAK DEMAND FOR PECO
GEOGRAPHIC ZONE



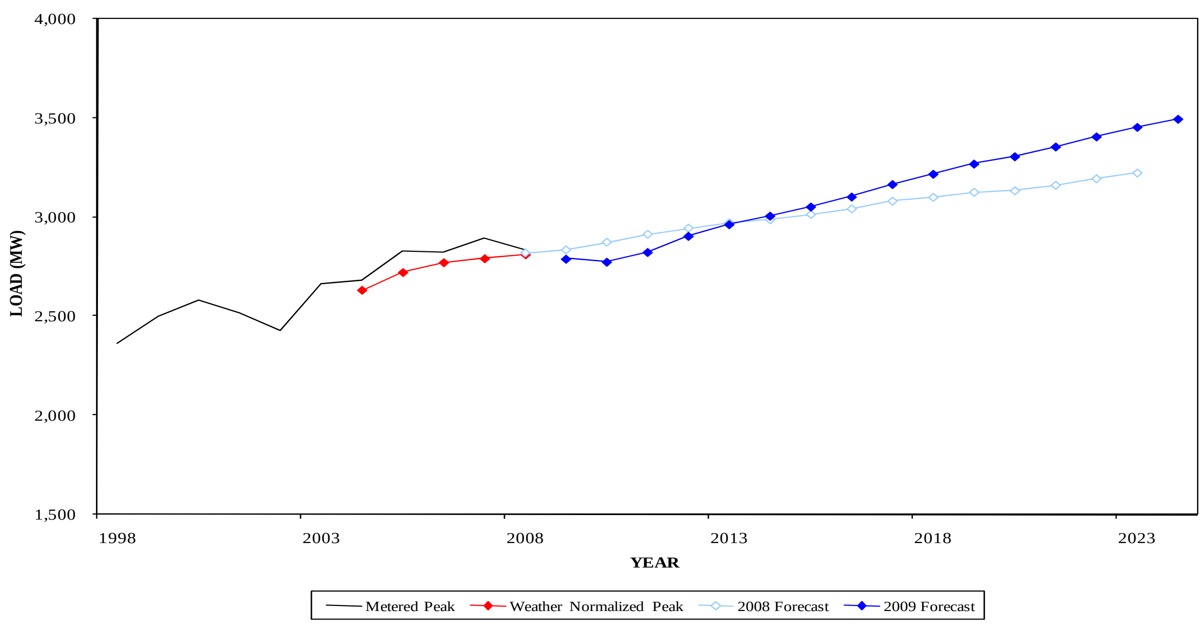
WINTER PEAK DEMAND FOR PECO
GEOGRAPHIC ZONE



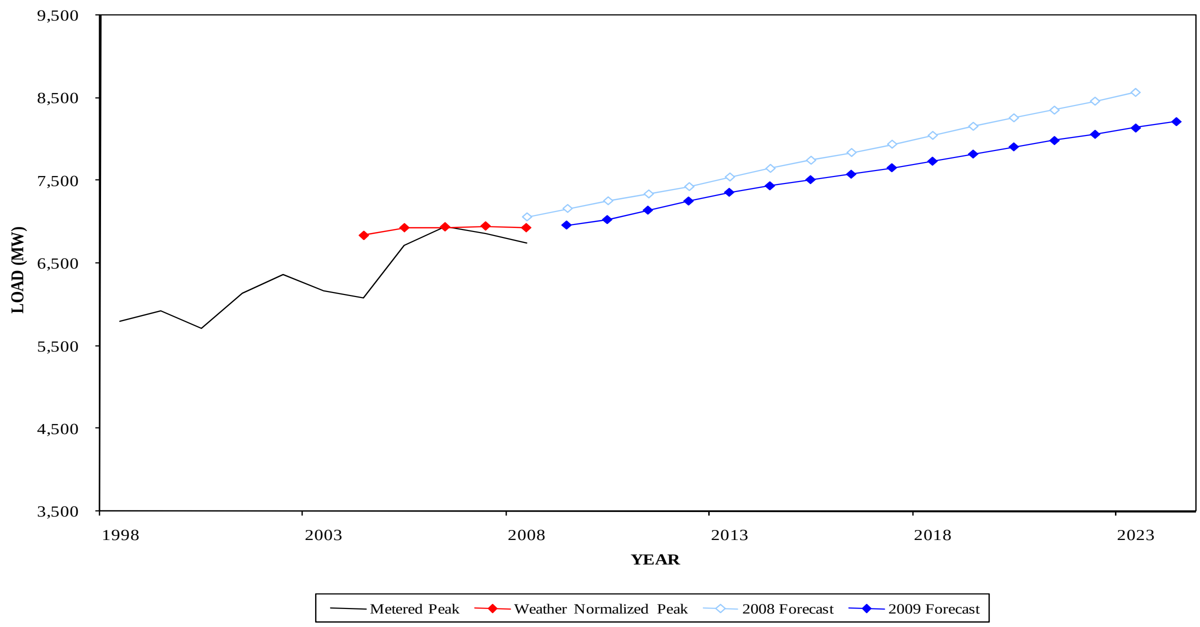
SUMMER PEAK DEMAND FOR PENLC GEOGRAPHIC ZONE



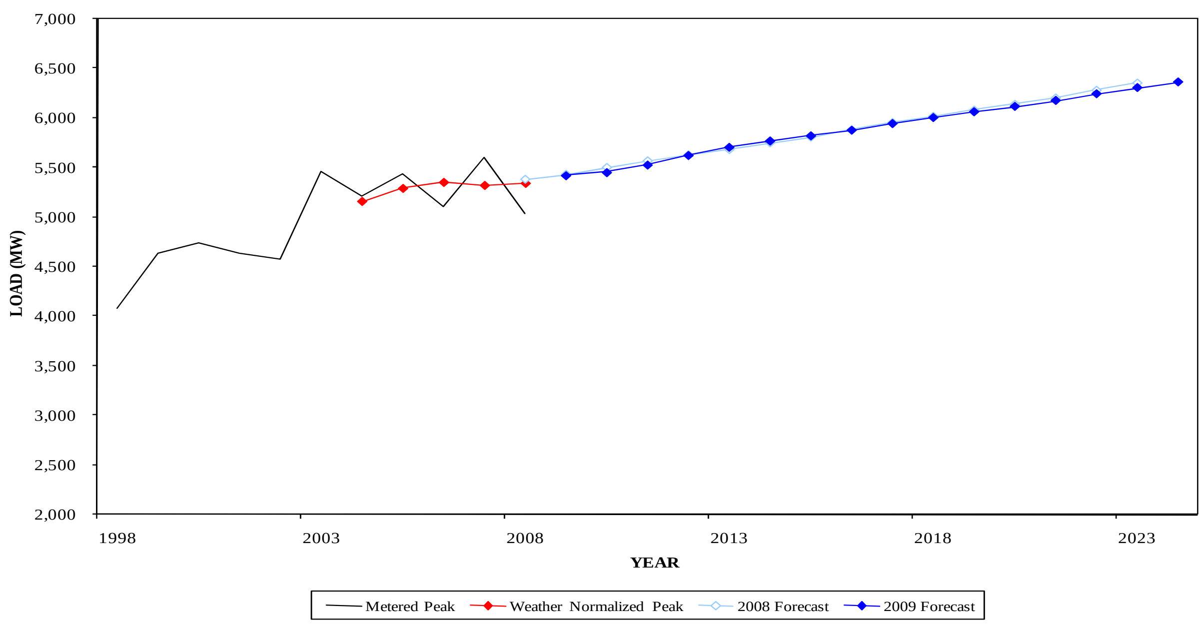
WINTER PEAK DEMAND FOR PENLC GEOGRAPHIC ZONE



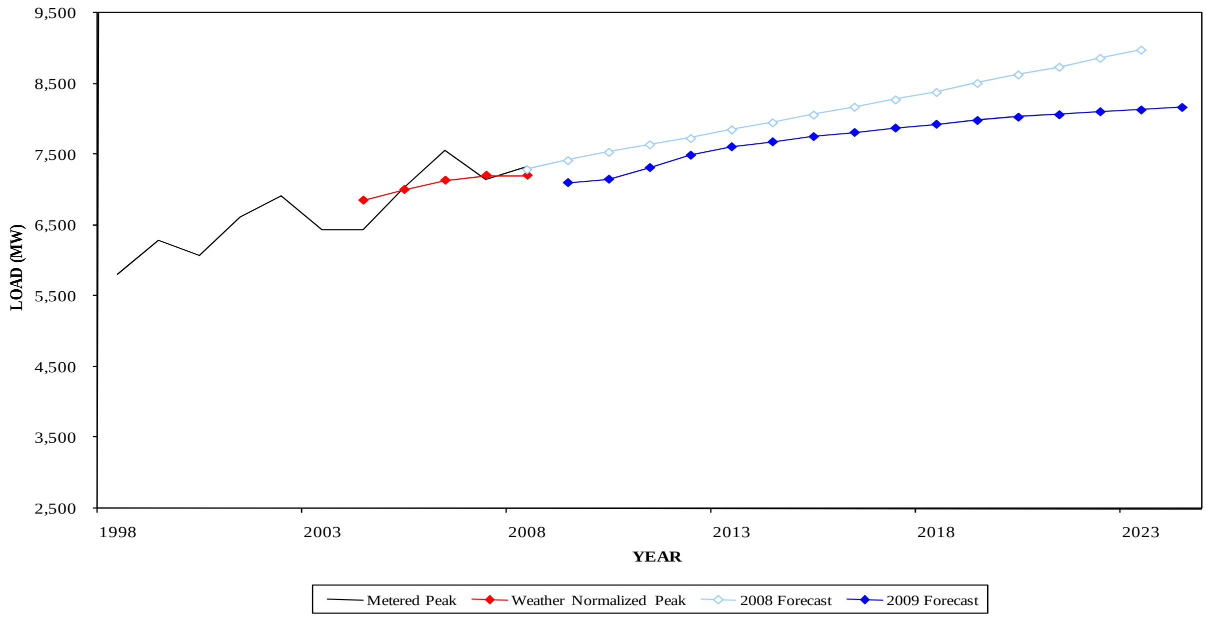
SUMMER PEAK DEMAND FOR PEPCO GEOGRAPHIC ZONE



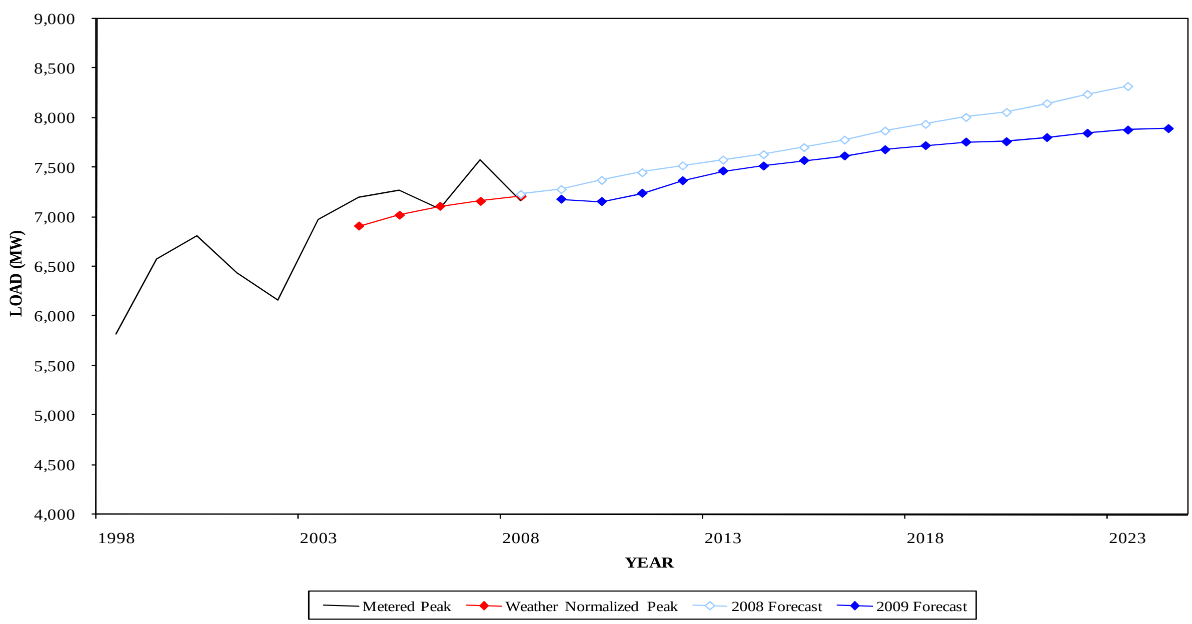
WINTER PEAK DEMAND FOR PEPCO GEOGRAPHIC ZONE



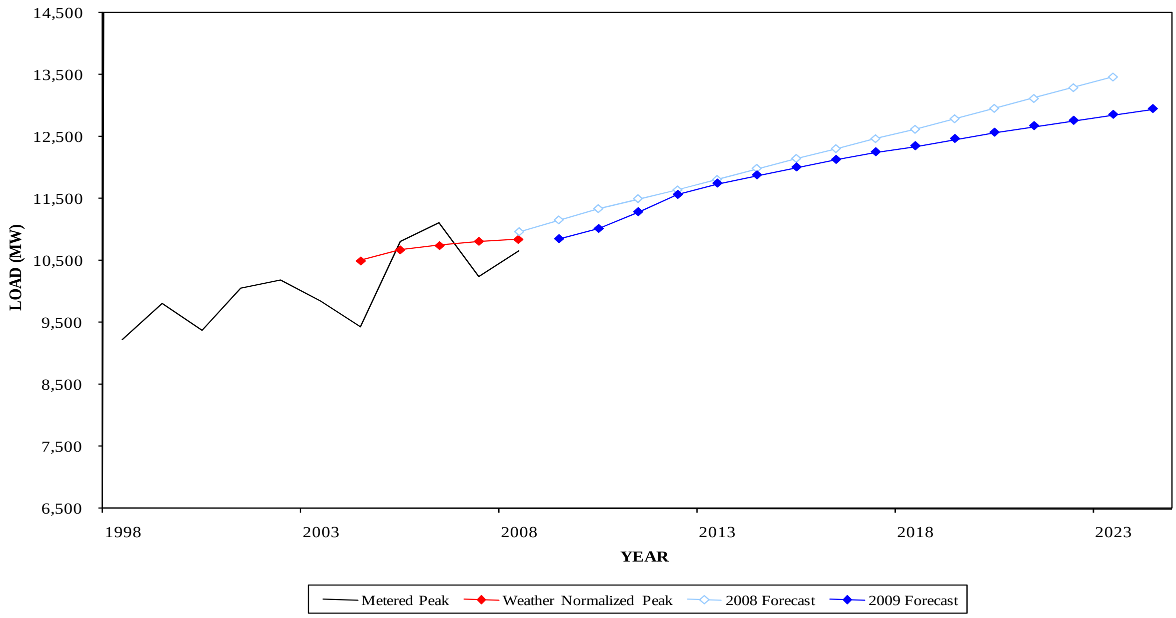
SUMMER PEAK DEMAND FOR PL GEOGRAPHIC ZONE



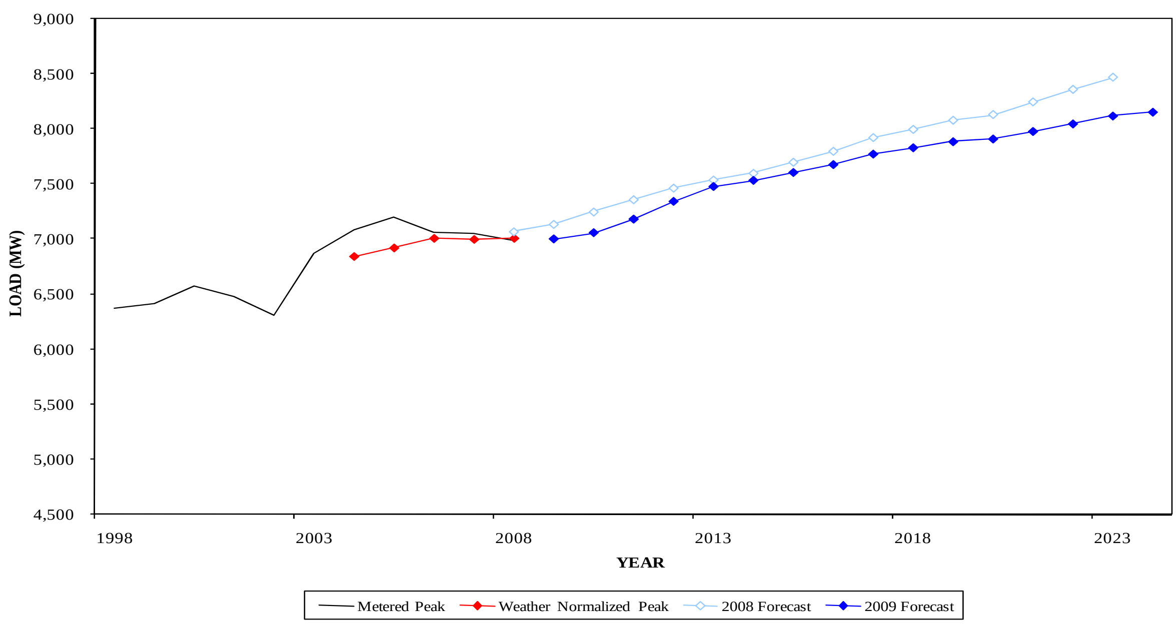
WINTER PEAK DEMAND FOR PL GEOGRAPHIC ZONE

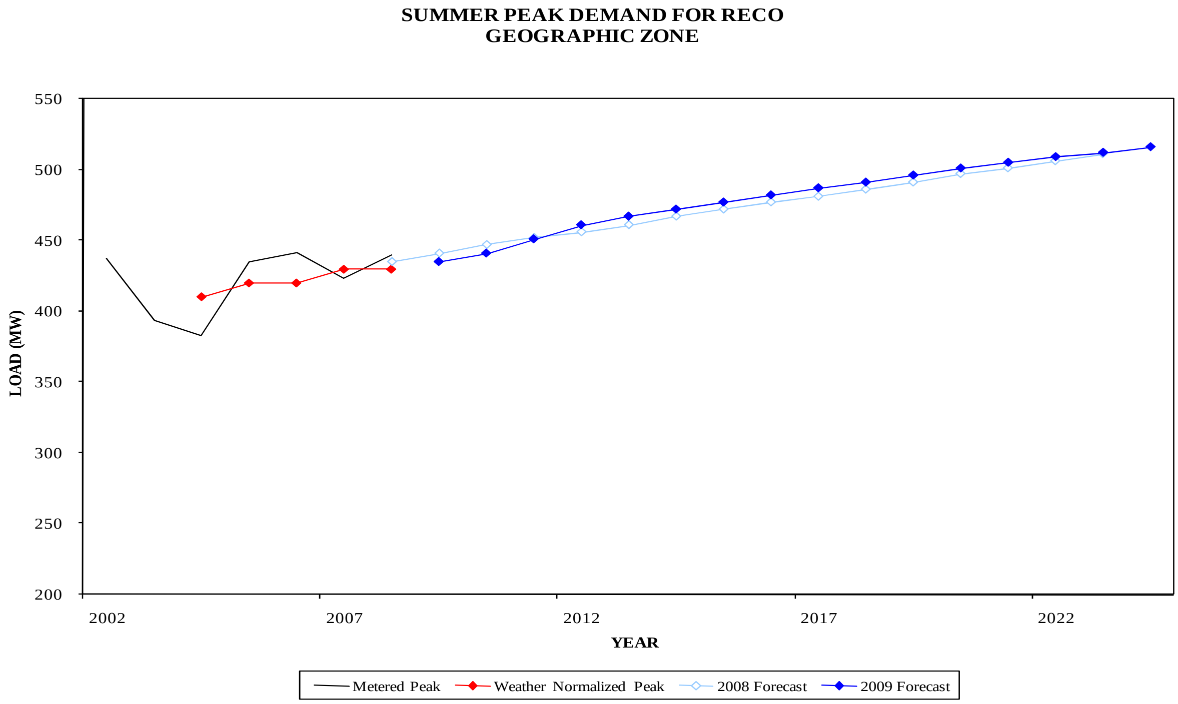


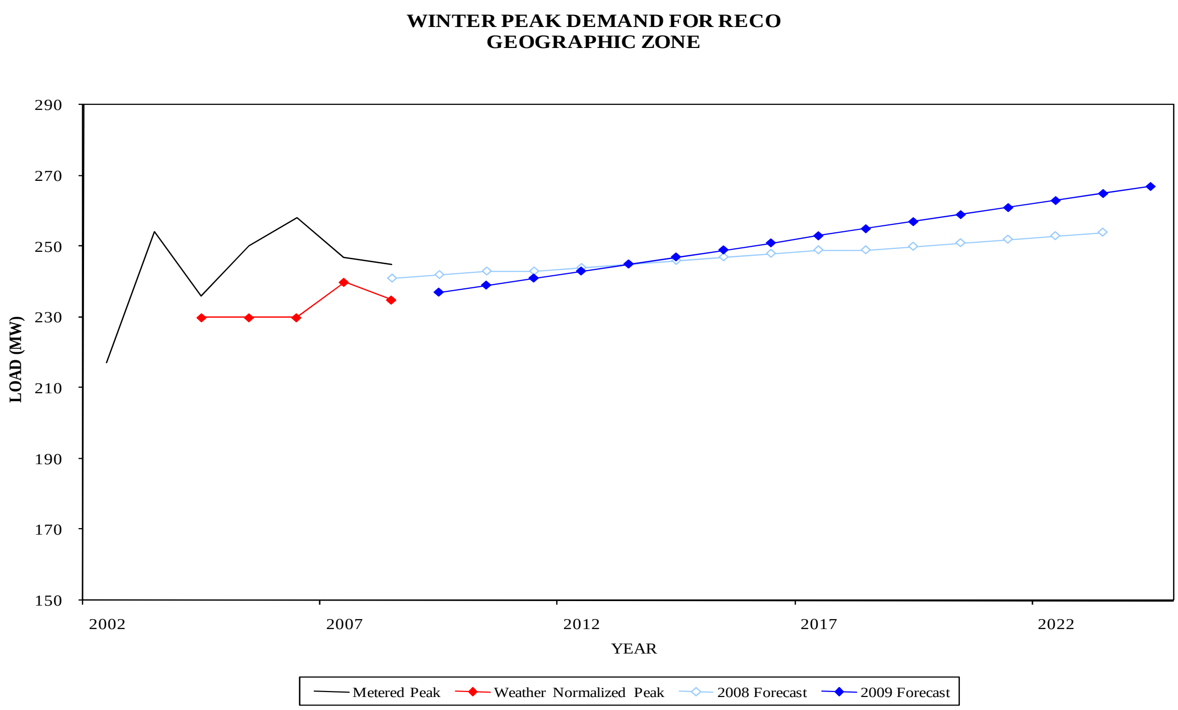
SUMMER PEAK DEMAND FOR PS GEOGRAPHIC ZONE



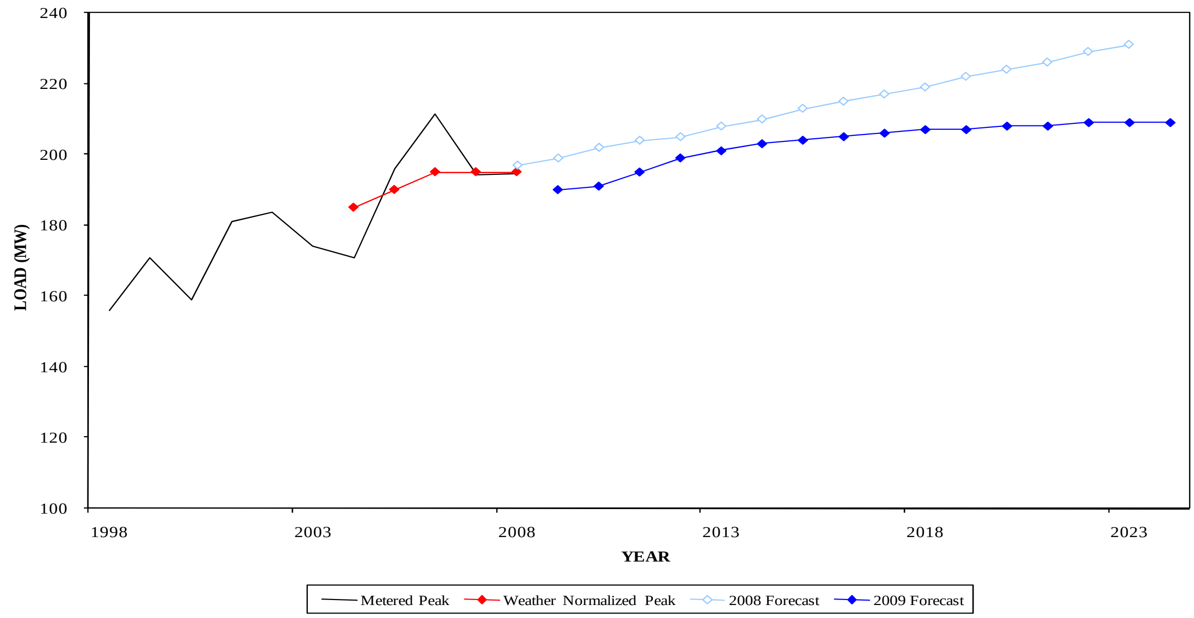
WINTER PEAK DEMAND FOR PS GEOGRAPHIC ZONE



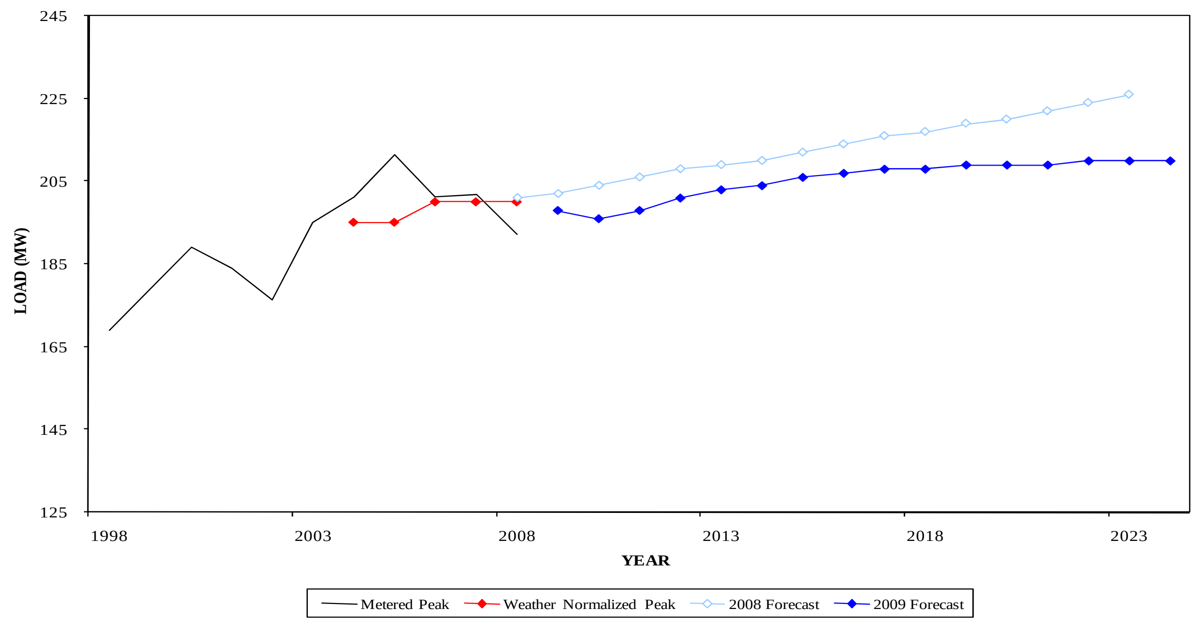

SUMMER PEAK DEMAND FOR RECO
GEOGRAPHIC ZONE
550
500
450
400
350
300
250
200
LOAD (MW)
2002
2007
2012
2017
2022
YEAR
Metered Peak
Weather Normalized Peak
2008 Forecast
2009 Forecast


WINTER PEAK DEMAND FOR RECO
GEOGRAPHIC ZONE
290
270
250
230
210
190
170
150
LOAD (MW)
2002
2007
2012
2017
2022
YEAR
Metered Peak
Weather Normalized Peak
2008 Forecast
2009 Forecast

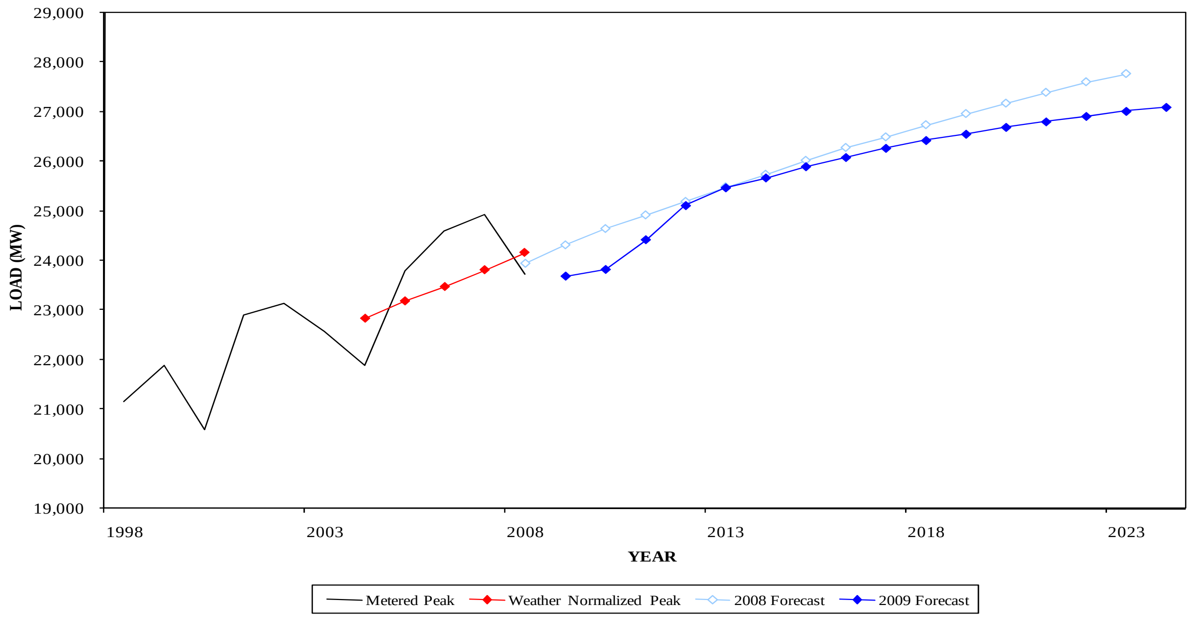
SUMMER PEAK DEMAND FOR UGI GEOGRAPHIC ZONE



WINTER PEAK DEMAND FOR UGI GEOGRAPHIC ZONE



SUMMER PEAK DEMAND FOR AEP GEOGRAPHIC ZONE



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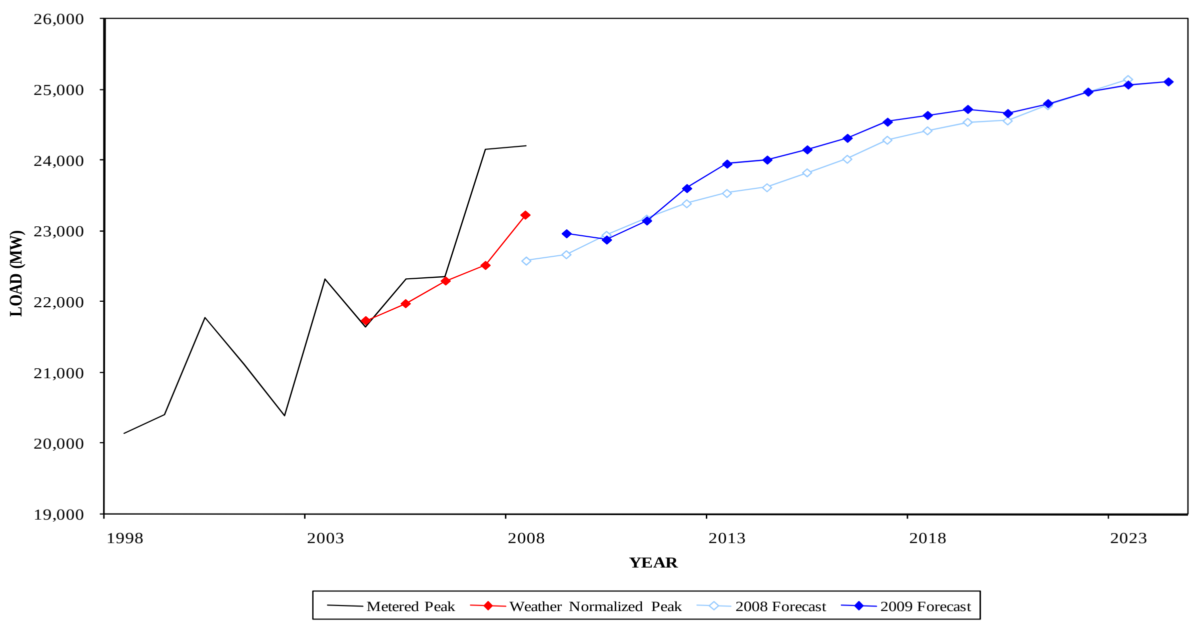

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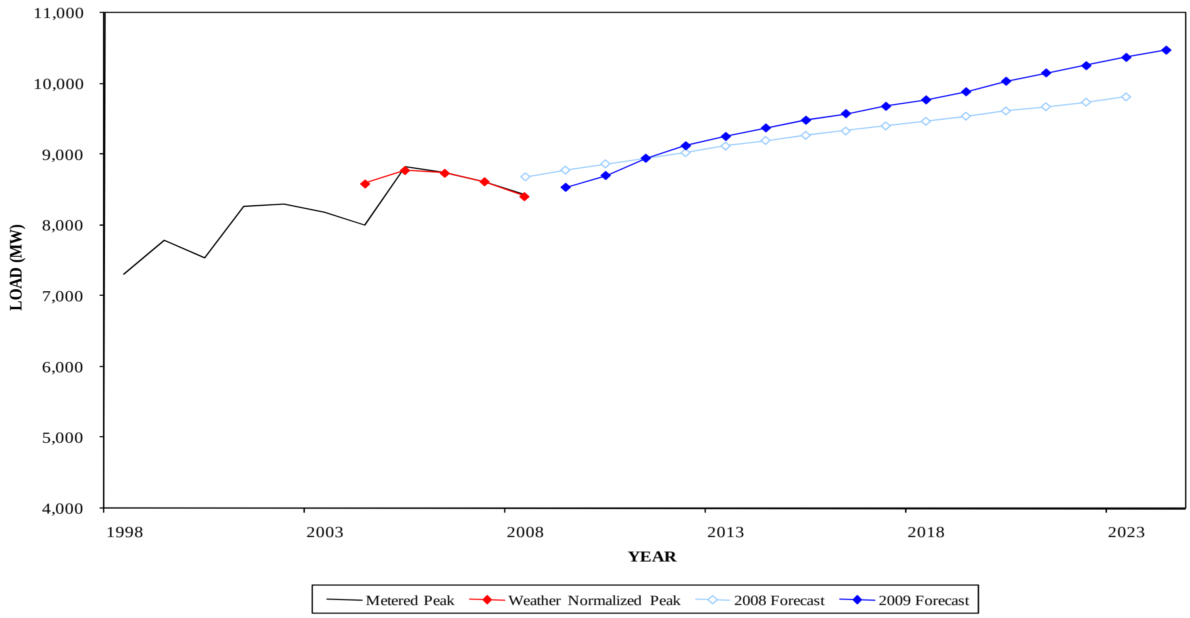
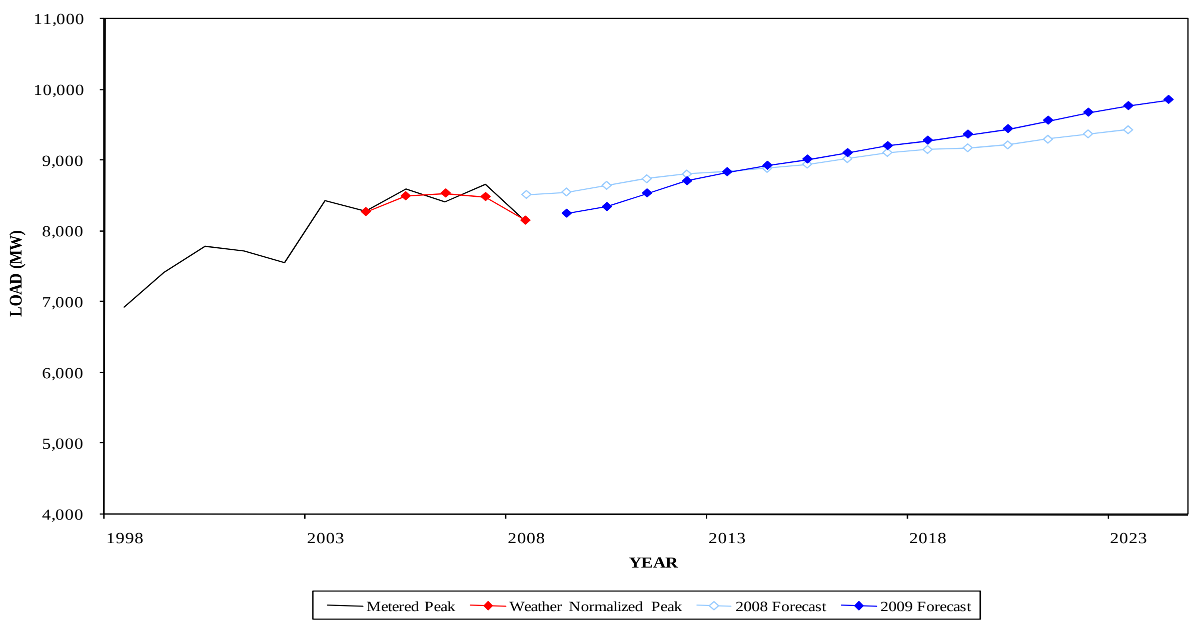
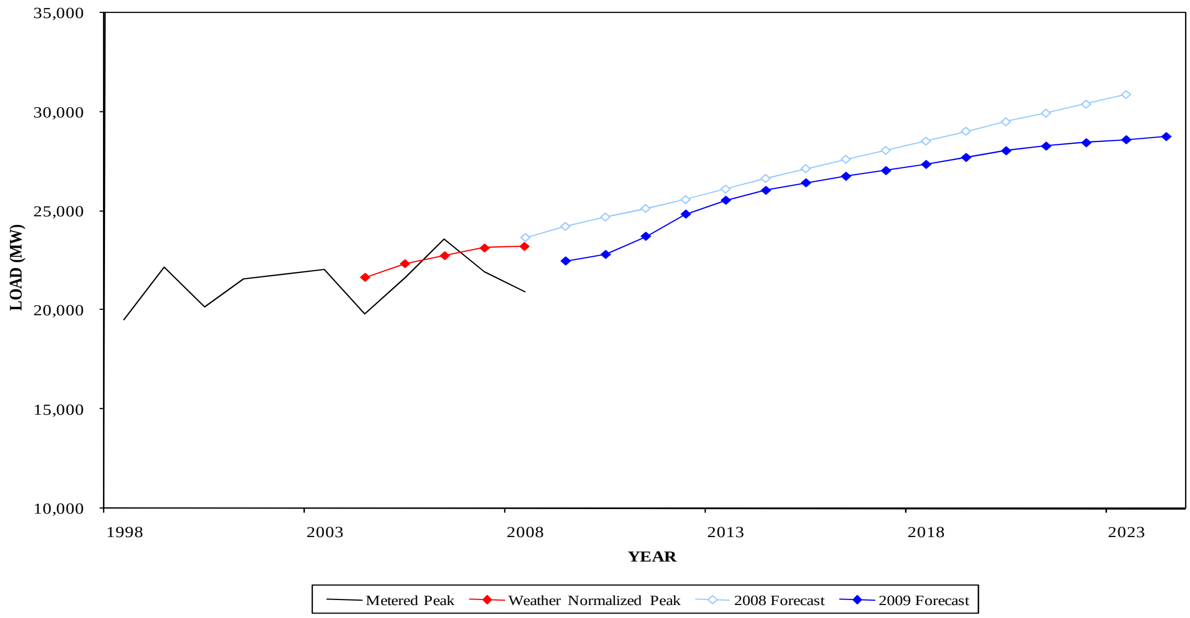


WINTER PEAK DEMAND FOR APS GEOGRAPHIC ZONE



SUMMER PEAK DEMAND FOR COMED GEOGRAPHIC ZONE



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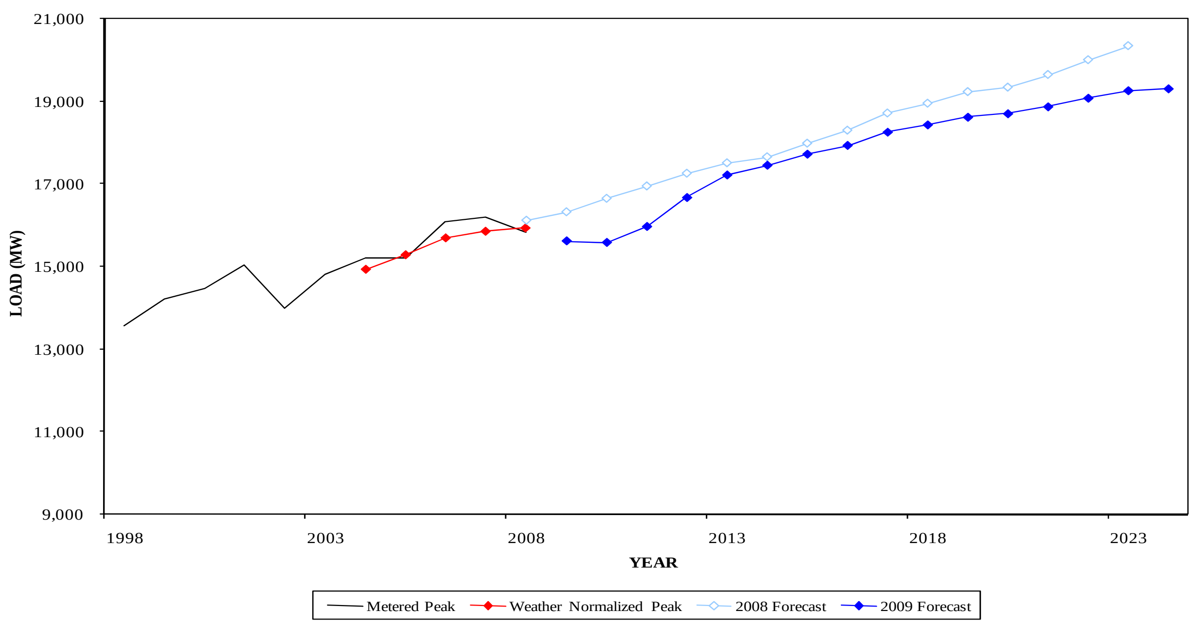
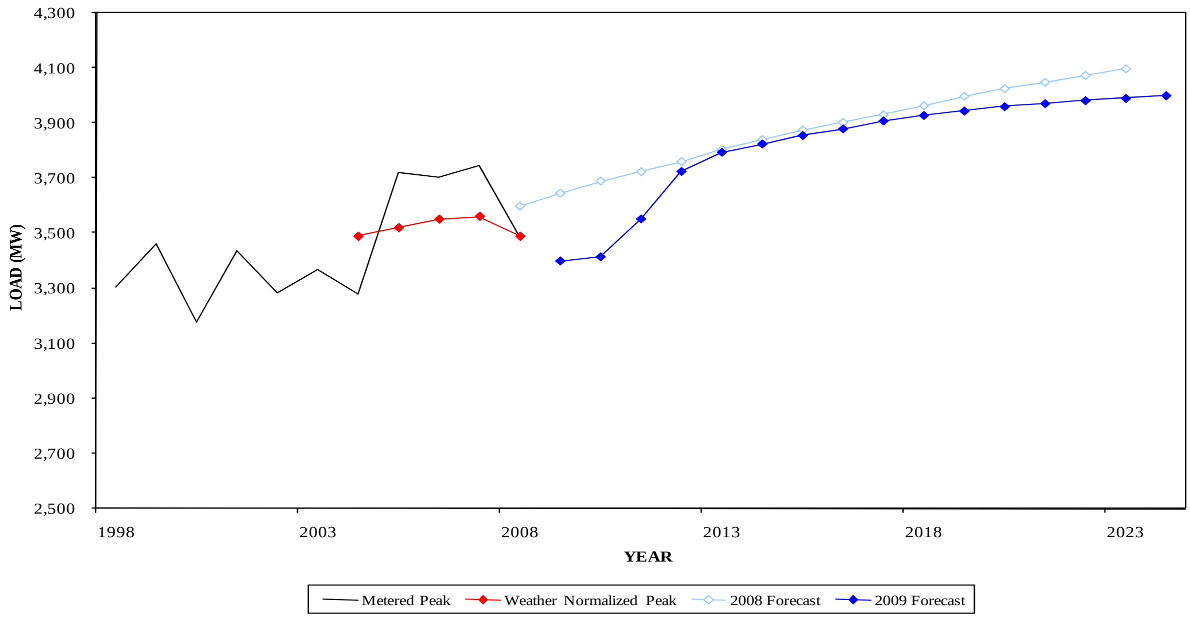
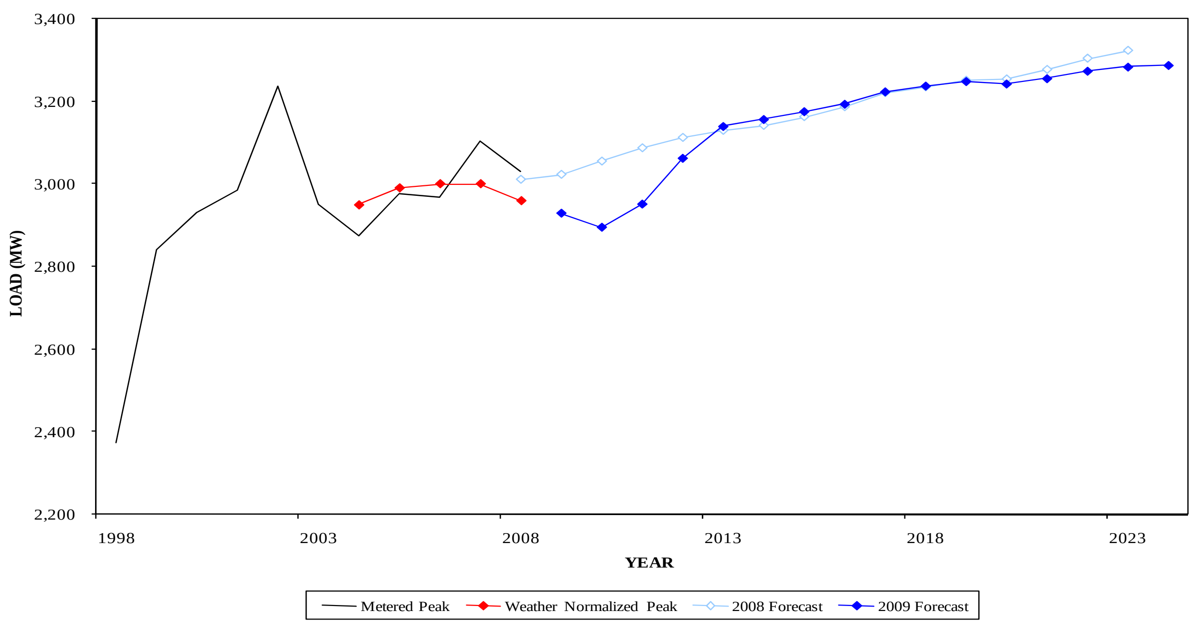


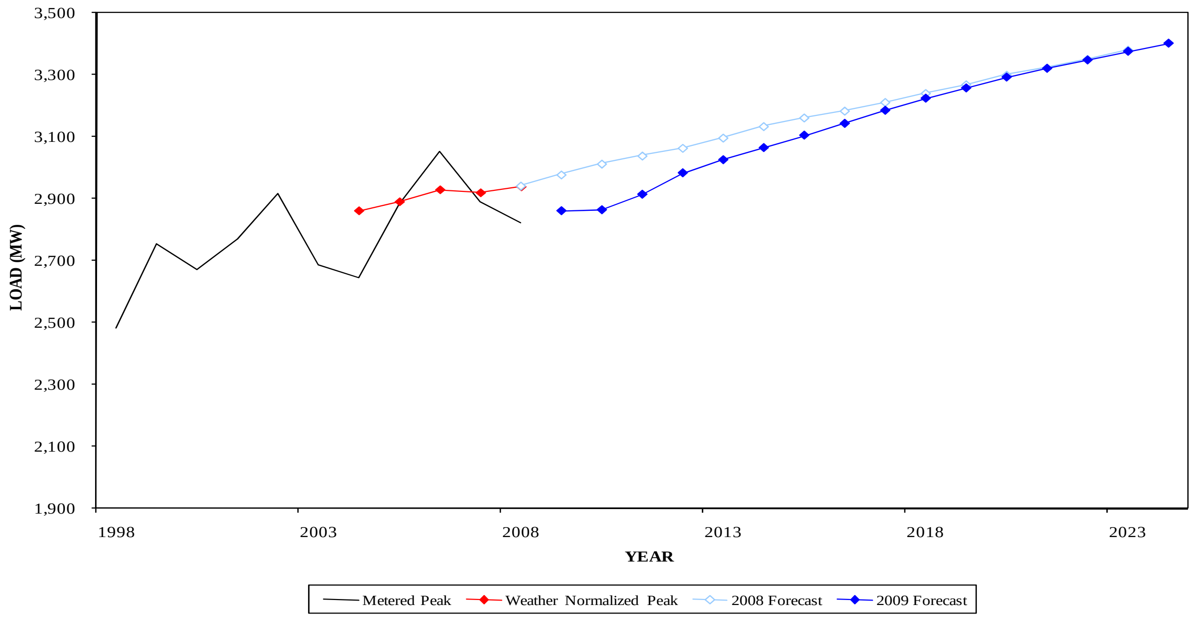
SUMMER PEAK DEMAND FOR DAY
GEOGRAPHIC ZONE



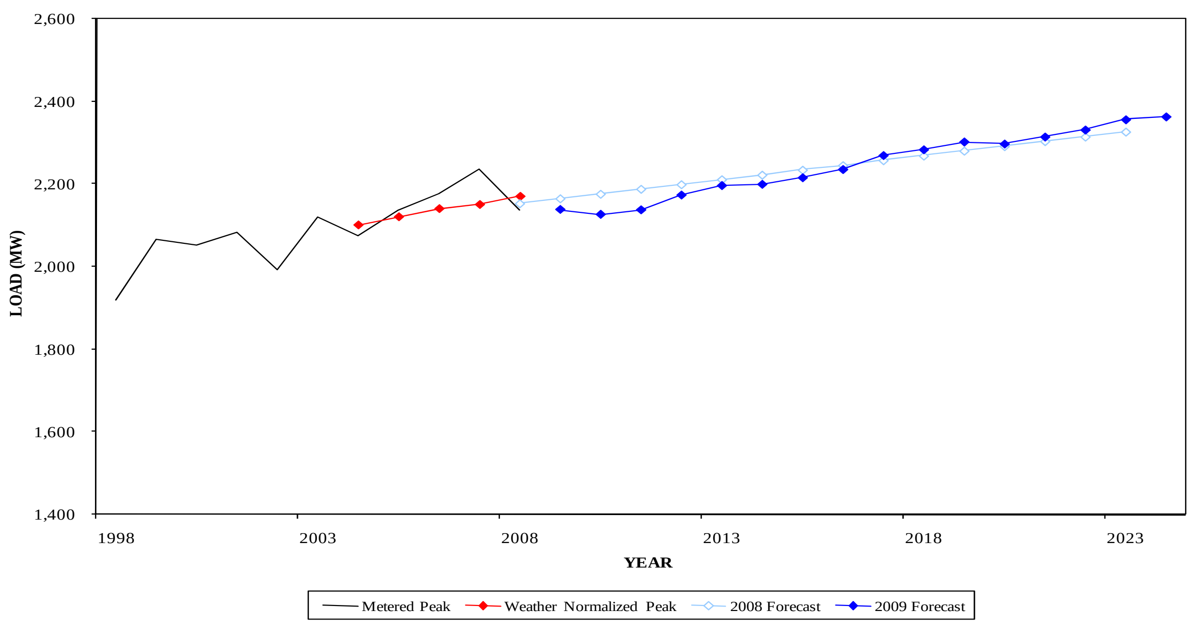
WINTER PEAK DEMAND FOR DAY
GEOGRAPHIC ZONE



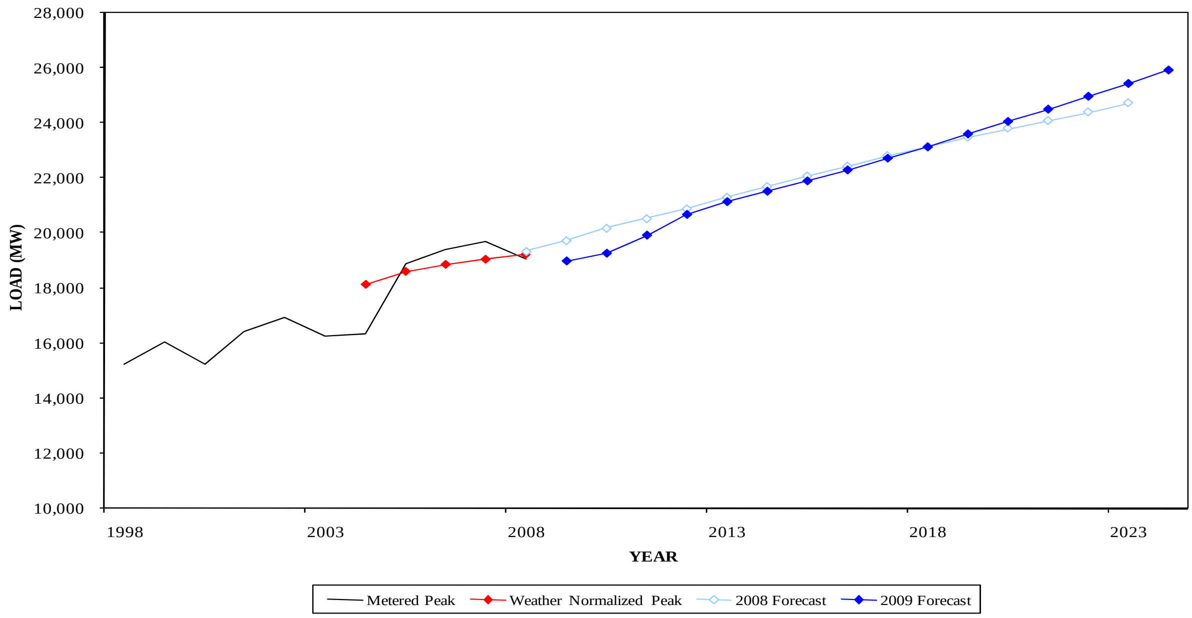
SUMMER PEAK DEMAND FOR DLCO GEOGRAPHIC ZONE



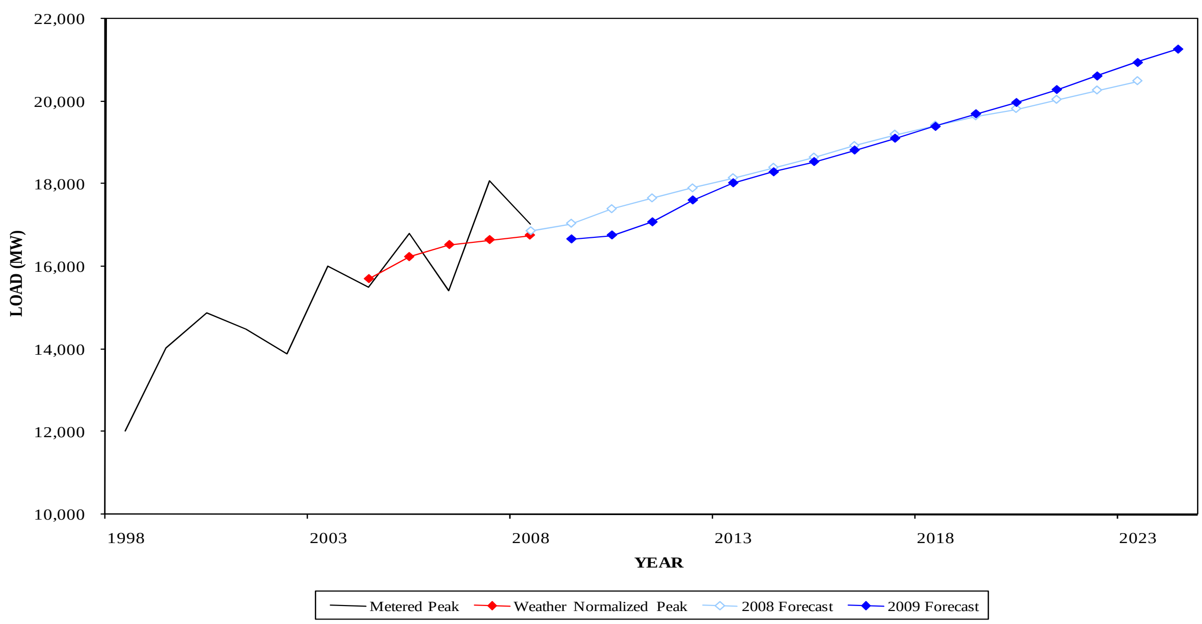
WINTER PEAK DEMAND FOR DLCO GEOGRAPHIC ZONE



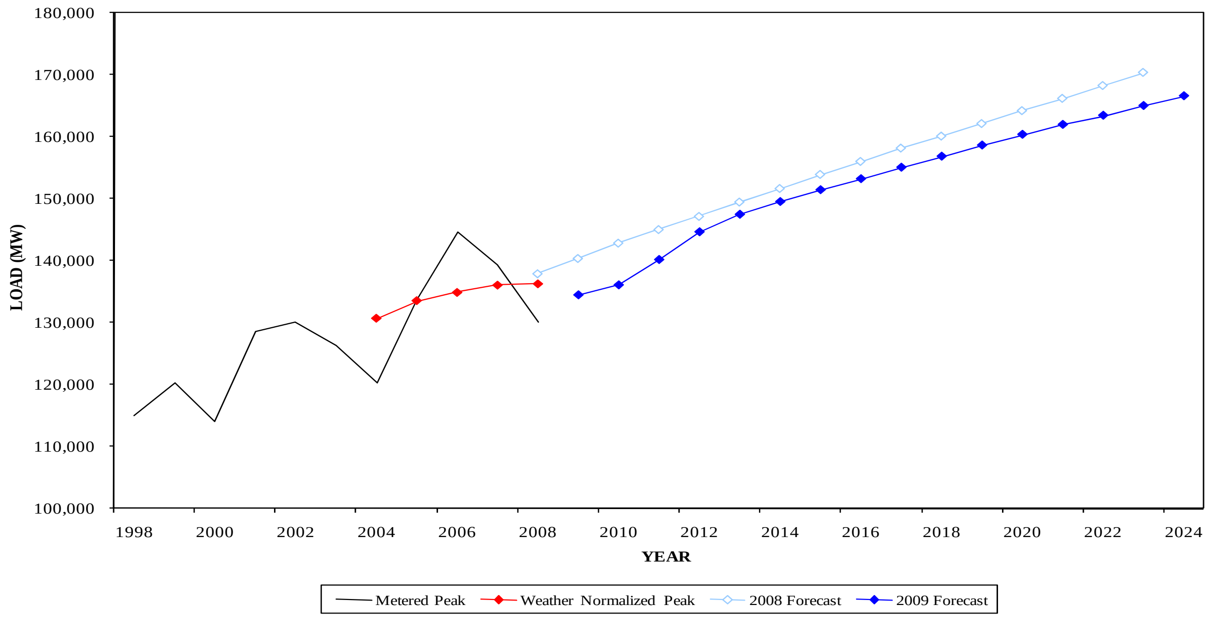
SUMMER PEAK DEMAND FOR DOM GEOGRAPHIC ZONE



WINTER PEAK DEMAND FOR DOM GEOGRAPHIC ZONE



SUMMER PEAK DEMAND FOR PJM RTO



WINTER PEAK DEMAND FOR PJM RTO

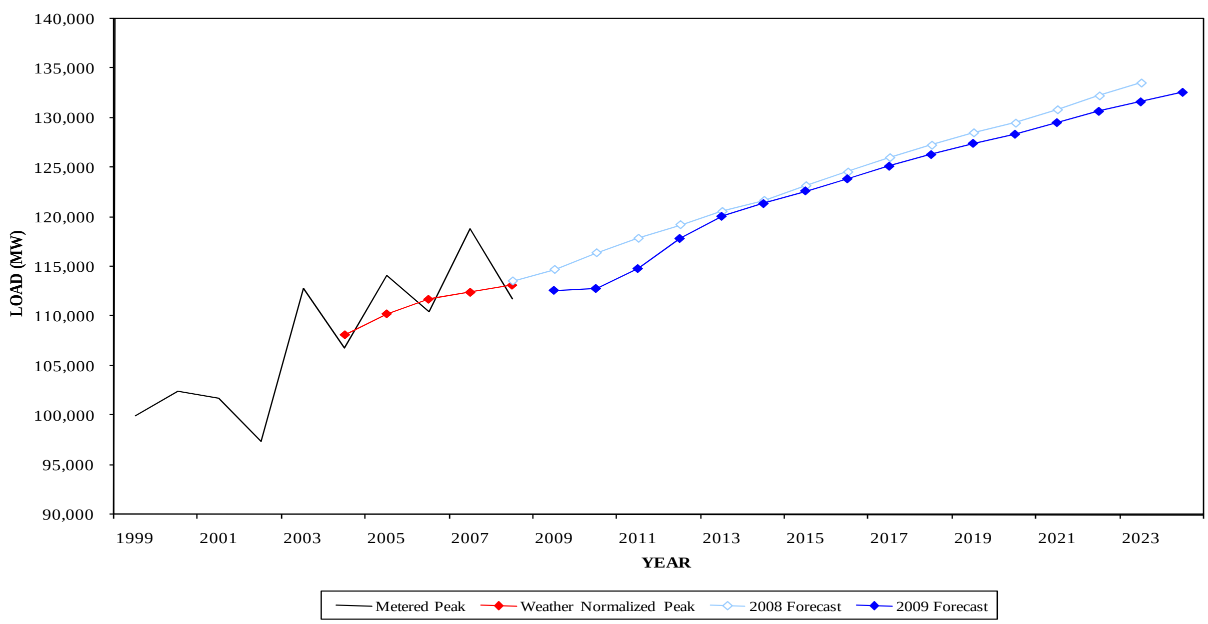


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Table A-1

PJM MID-ATLANTIC REGION
SUMMER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST
TO THE JANUARY 2008 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	2009		2014		2019	
	MW	%	MW	%	MW	%
AE	(205)	-7.1%	(139)	-4.0%	(200)	-5.4%
BGE	(152)	-2.0%	164	2.1%	541	6.6%
DPL	(306)	-7.2%	(216)	-4.6%	(268)	-5.2%
JCPL	(279)	-4.2%	(173)	-2.4%	(414)	-5.2%
METED	(116)	-3.9%	(52)	-1.6%	(156)	-4.5%
PECO	(454)	-5.1%	(474)	-4.9%	(675)	-6.6%
PENLC	(106)	-3.7%	(7)	-0.2%	120	3.8%
PEPCO	(199)	-2.8%	(208)	-2.7%	(333)	-4.1%
PL	(314)	-4.2%	(268)	-3.4%	(521)	-6.1%
PS	(300)	-2.7%	(105)	-0.9%	(322)	-2.5%
RECO	(6)	-1.4%	5	1.1%	5	1.0%
UGI	(9)	-4.5%	(7)	-3.3%	(15)	-6.8%
PJM MID-ATLANTIC	(2,201)	-3.6%	(1,237)	-1.9%	(1,966)	-2.8%
FE/GPU	(469)	-3.8%	(159)	-1.2%	(363)	-2.5%
PLGRP	(350)	-4.6%	(306)	-3.8%	(568)	-6.5%

Table A-1

PJM WESTERN REGION, PJM SOUTHERN REGION AND PJM RTO
SUMMER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST
TO THE JANUARY 2008 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	2009		2014		2019	
	MW	%	MW	%	MW	%
AEP	(629)	-2.6%	(68)	-0.3%	(407)	-1.5%
APS	(245)	-2.8%	175	1.9%	341	3.6%
COMED	(1,747)	-7.2%	(587)	-2.2%	(1,303)	-4.5%
DAY	(245)	-6.7%	(14)	-0.4%	(52)	-1.3%
DLCO	(116)	-3.9%	(69)	-2.2%	(12)	-0.4%
PJM WESTERN	(2,796)	-4.5%	(589)	-0.9%	(1,441)	-2.0%
DOM	(761)	-3.9%	(186)	-0.9%	114	0.5%
PJM RTO	(5,979)	-4.3%	(2,178)	-1.4%	(3,515)	-2.2%

Table A-2

PJM MID-ATLANTIC REGION
WINTER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST
TO THE JANUARY 2008 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	08/09		13/14		18/19	
	MW	%	MW	%	MW	%
AE	(81)	-4.3%	(42)	-1.9%	(69)	-2.9%
BGE	(61)	-1.0%	38	0.6%	205	3.2%
DPL	(135)	-3.9%	(103)	-2.8%	(133)	-3.4%
JCPL	(88)	-2.2%	(18)	-0.4%	(117)	-2.5%
METED	(36)	-1.4%	4	0.1%	(44)	-1.5%
PECO	(156)	-2.3%	(246)	-3.5%	(362)	-4.8%
PENLC	(45)	-1.6%	20	0.7%	143	4.6%
PEPCO	(12)	-0.2%	19	0.3%	(19)	-0.3%
PL	(99)	-1.4%	(116)	-1.5%	(249)	-3.1%
PS	(138)	-1.9%	(65)	-0.9%	(192)	-2.4%
RECO	(5)	-2.1%	1	0.4%	7	2.8%
UGI	(4)	-2.0%	(6)	-2.9%	(10)	-4.6%
PJM MID-ATLANTIC	(657)	-1.4%	(216)	-0.4%	(536)	-1.0%
FE/GPU	(179)	-1.9%	14	0.1%	2	0.0%
PLGRP	(123)	-1.6%	(138)	-1.8%	(289)	-3.5%

Table A-2

PJM WESTERN REGION, PJM SOUTHERN REGION AND PJM RTO
WINTER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST
TO THE JANUARY 2008 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	08/09		13/14		18/19	
	MW	**%**	**MW**	**%**	**MW**	**%**
AEP	297	1.3%	394	1.7%	189	0.8%
APS	(300)	-3.5%	42	0.5%	191	2.1%
COMED	(714)	-4.4%	(204)	-1.2%	(610)	-3.2%
DAY	(94)	-3.1%	15	0.5%	(2)	-0.1%
DLCO	(27)	-1.2%	(23)	-1.0%	22	1.0%
PJM WESTERN	(692)	-1.3%	481	0.9%	32	0.1%
DOM	(366)	-2.1%	(97)	-0.5%	65	0.3%
PJM RTO	(2,165)	-1.9%	(341)	-0.3%	(1,057)	-0.8%

PJM CONTROL AREA - JANUARY 2009
UNRESTRICTED PEAK FORECAST: SUMMER/WINTER
2009-2019

SUMMER UNRESTRICTED PEAK (MW)

		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Annual Growth Rate (10 yr)
PJM MID-ATLANTIC		59,621	60,341	62,027	63,556	64,706	65,581	66,403	67,197	67,969	68,717	69,512	1.5%
	%		1.2%	2.8%	2.5%	1.8%	1.4%	1.3%	1.2%	1.1%	1.1%	1.2%	
PJM WESTERN		59,701	60,280	62,141	64,318	65,598	66,421	67,182	67,876	68,500	69,079	69,721	1.6%
	%		1.0%	3.1%	3.5%	2.0%	1.3%	1.1%	1.0%	0.9%	0.8%	0.9%	
PJM SOUTHERN		18,982	19,264	19,921	20,675	21,140	21,518	21,895	22,294	22,721	23,130	23,603	2.2%
	%		1.5%	3.4%	3.8%	2.2%	1.8%	1.8%	1.8%	1.9%	1.8%	2.0%	
PJM RTO		134,428	136,038	140,132	144,613	147,442	149,497	151,410	153,189	155,042	156,822	158,617	1.7%
	%		1.2%	3.0%	3.2%	2.0%	1.4%	1.3%	1.2%	1.2%	1.1%	1.1%	

WINTER UNRESTRICTED PEAK (MW)

		08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	Annual Growth Rate (10 yr)
PJM MID-ATLANTIC		46,444	46,522	47,343	48,465	49,236	49,807	50,335	50,834	51,376	51,852	52,299	1.2%
	%		0.2%	1.8%	2.4%	1.6%	1.2%	1.1%	1.0%	1.1%	0.9%	0.9%	
PJM WESTERN		50,819	50,814	51,743	53,212	54,207	54,721	55,195	55,661	56,243	56,633	56,939	1.1%
	%		0.0%	1.8%	2.8%	1.9%	0.9%	0.9%	0.8%	1.0%	0.7%	0.5%	
PJM SOUTHERN		16,677	16,773	17,089	17,621	18,037	18,302	18,551	18,831	19,117	19,403	19,710	1.7%
	%		0.6%	1.9%	3.1%	2.4%	1.5%	1.4%	1.5%	1.5%	1.5%	1.6%	
PJM RTO		112,563	112,750	114,762	117,809	120,056	121,344	122,628	123,847	125,124	126,300	127,440	1.2%
	%		0.2%	1.8%	2.7%	1.9%	1.1%	1.1%	1.0%	1.0%	0.9%	0.9%	

Notes:
Projected PJM seasonal peak load at normal peak weather conditions in the absense of any load reductions due to load management, voltage reductions or voluntary curtailments.
The above forecasts incorporate all load in the PJM Control Area, including members and non-members.

PJM CONTROL AREA - JANUARY 2009
UNRESTRICTED PEAK FORECAST: SUMMER/WINTER
2020-2024

SUMMER UNRESTRICTED PEAK (MW)

		2020	2021	2022	2023	2024	Annual Growth Rate (15 yr)
PJM MID-ATLANTIC		70,342	71,036	71,723	72,267	72,986	1.4%
	%	1.2%	1.0%	1.0%	0.8%	1.0%	
PJM WESTERN		70,324	70,843	71,261	71,618	72,013	1.3%
	%	0.9%	0.7%	0.6%	0.5%	0.6%	
PJM SOUTHERN		24,059	24,506	24,974	25,440	25,929	2.1%
	%	1.9%	1.9%	1.9%	1.9%	1.9%	
PJM RTO		160,357	161,954	163,433	165,006	166,581	1.4%
	%	1.1%	1.0%	0.9%	1.0%	1.0%	

WINTER UNRESTRICTED PEAK (MW)

		19/20	20/21	21/22	22/23	23/24	Annual Growth Rate (15 yr)
PJM MID-ATLANTIC		52,712	53,156	53,621	54,015	54,412	1.1%
	%	0.8%	0.8%	0.9%	0.7%	0.7%	
PJM WESTERN		57,252	57,608	58,021	58,332	58,566	1.0%
	%	0.5%	0.6%	0.7%	0.5%	0.4%	
PJM SOUTHERN		19,983	20,297	20,626	20,952	21,276	1.6%
	%	1.4%	1.6%	1.6%	1.6%	1.5%	
PJM RTO		128,358	129,537	130,679	131,639	132,599	1.1%
	%	0.7%	0.9%	0.9%	0.7%	0.7%	

Notes:
Projected PJM seasonal peak load at normal peak weather conditions in the absense of any load reductions due to load management, voltage reductions or voluntary curtailments.
The above forecasts incorporate all load in the PJM Control Area, including members and non-members.

Table B-1

SUMMER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION 2009-2019

		METERED 2008	UNRESTRICTED 2008	NORMAL 2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Annual Growth Rate (10 yr)
AE		2,638	2,638	2,750	2,692	2,761	2,980	3,120	3,240	3,301	3,351	3,402	3,448	3,494	3,533	2.8%
	%				-2.1%	2.6%	7.9%	4.7%	3.8%	1.9%	1.5%	1.5%	1.4%	1.3%	1.1%	
BGE		6,929	7,150	7,270	7,303	7,446	7,668	7,764	7,887	8,022	8,176	8,304	8,447	8,586	8,745	1.8%
	%				0.5%	2.0%	3.0%	1.3%	1.6%	1.7%	1.9%	1.6%	1.7%	1.6%	1.9%	
DPL		3,985	4,009	4,010	3,972	4,002	4,138	4,289	4,395	4,483	4,554	4,630	4,712	4,789	4,882	2.1%
	%				-0.9%	0.8%	3.4%	3.6%	2.5%	2.0%	1.6%	1.7%	1.8%	1.6%	1.9%	
JCPL		6,299	6,398	6,380	6,357	6,504	6,717	6,931	7,073	7,173	7,269	7,364	7,457	7,541	7,621	1.8%
	%				-0.4%	2.3%	3.3%	3.2%	2.0%	1.4%	1.3%	1.3%	1.3%	1.1%	1.1%	
METED		3,045	3,110	2,880	2,866	2,906	2,995	3,079	3,142	3,182	3,219	3,253	3,284	3,305	3,334	1.5%
	%				-0.5%	1.4%	3.1%	2.8%	2.0%	1.3%	1.2%	1.1%	1.0%	0.6%	0.9%	
PECO		8,824	8,837	8,690	8,455	8,459	8,681	8,893	9,008	9,103	9,212	9,307	9,386	9,467	9,538	1.2%
	%				-2.7%	0.0%	2.6%	2.4%	1.3%	1.1%	1.2%	1.0%	0.8%	0.9%	0.7%	
PENLC		2,880	2,880	2,840	2,786	2,806	2,877	2,949	3,001	3,047	3,098	3,152	3,205	3,252	3,305	1.7%
	%				-1.9%	0.7%	2.5%	2.5%	1.8%	1.5%	1.7%	1.7%	1.7%	1.5%	1.6%	
PEPCO		6,751	6,752	6,930	6,960	7,026	7,141	7,252	7,358	7,437	7,512	7,578	7,657	7,736	7,823	1.2%
	%				0.4%	0.9%	1.6%	1.6%	1.5%	1.1%	1.0%	0.9%	1.0%	1.0%	1.1%	
PL		7,316	7,370	7,200	7,106	7,155	7,319	7,494	7,613	7,683	7,757	7,816	7,878	7,932	7,985	1.2%
	%				-1.3%	0.7%	2.3%	2.4%	1.6%	0.9%	1.0%	0.8%	0.8%	0.7%	0.7%	
PS		10,654	10,716	10,850	10,858	11,022	11,292	11,570	11,753	11,885	12,013	12,135	12,257	12,354	12,470	1.4%
	%				0.1%	1.5%	2.4%	2.5%	1.6%	1.1%	1.1%	1.0%	1.0%	0.8%	0.9%	
RECO		440	440	430	435	441	451	461	467	472	477	482	487	491	496	1.3%
	%				1.2%	1.4%	2.3%	2.2%	1.3%	1.1%	1.1%	1.0%	1.0%	0.8%	1.0%	
UGI		195	195	195	190	191	195	199	201	203	204	205	206	207	207	0.9%
	%				-2.6%	0.5%	2.1%	2.1%	1.0%	1.0%	0.5%	0.5%	0.5%	0.5%	0.0%	
DIVERSITY (-)					359	378	427	445	432	410	439	431	455	437	427	
PJM MID-ATLANTIC		59,653	60,192	60,120	59,621	60,341	62,027	63,556	64,706	65,581	66,403	67,197	67,969	68,717	69,512	1.5%
	%				-0.8%	1.2%	2.8%	2.5%	1.8%	1.4%	1.3%	1.2%	1.1%	1.1%	1.2%	
FE/GPU		12,028	12,136	11,970	11,866	12,052	12,421	12,803	13,082	13,284	13,458	13,632	13,806	13,972	14,141	1.8%
	%				1.5%	1.6%	3.1%	3.1%	2.2%	1.5%	1.3%	1.3%	1.3%	1.2%	1.2%	
PLGRP		7,510	7,564	7,360	7,266	7,305	7,471	7,649	7,773	7,851	7,923	7,987	8,043	8,100	8,156	1.2%
	%				1.3%	0.5%	2.3%	2.4%	1.6%	1.0%	0.9%	0.8%	0.7%	0.7%	0.7%	

Note:
Normal 2008 and all forecast values are non-coincident as estimated by PJM staff.
Normal 2008 and all forecast values represent unrestricted peaks.

Table B-1 (Continued)

SUMMER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION 2020-2024

		2020	2021	2022	2023	2024	Annual Growth Rate (15 yr)
AE		3,572	3,617	3,658	3,687	3,722	2.2%
	%	1.1%	1.3%	1.1%	0.8%	0.9%	
BGE		8,913	9,050	9,184	9,323	9,483	1.8%
	%	1.9%	1.5%	1.5%	1.5%	1.7%	
DPL		4,969	5,059	5,142	5,232	5,317	2.0%
	%	1.8%	1.8%	1.6%	1.8%	1.6%	
JCPL		7,691	7,763	7,841	7,912	7,983	1.5%
	%	0.9%	0.9%	1.0%	0.9%	0.9%	
METED		3,364	3,384	3,407	3,424	3,442	1.2%
	%	0.9%	0.6%	0.7%	0.5%	0.5%	
PECO		9,616	9,678	9,728	9,765	9,806	1.0%
	%	0.8%	0.6%	0.5%	0.4%	0.4%	
PENLC		3,355	3,401	3,445	3,489	3,529	1.6%
	%	1.5%	1.4%	1.3%	1.3%	1.1%	
PEPCO		7,911	7,987	8,063	8,140	8,217	1.1%
	%	1.1%	1.0%	1.0%	1.0%	0.9%	
PL		8,032	8,066	8,108	8,134	8,170	0.9%
	%	0.6%	0.4%	0.5%	0.3%	0.4%	
PS		12,572	12,677	12,763	12,859	12,951	1.2%
	%	0.8%	0.8%	0.7%	0.8%	0.7%	
RECO		501	505	509	512	516	1.1%
	%	1.0%	0.8%	0.8%	0.6%	0.8%	
UGI		208	208	209	209	209	0.6%
	%	0.5%	0.0%	0.5%	0.0%	0.0%	
DIVERSITY (-)		362	359	334	419	359	
PJM MID-ATLANTIC		70,342	71,036	71,723	72,267	72,986	1.4%
	%	1.2%	1.0%	1.0%	0.8%	1.0%	
FE/GPU		14,285	14,422	14,564	14,691	14,844	1.5%
	%	1.0%	1.0%	1.0%	0.9%	1.0%	
PLGRP		8,199	8,235	8,278	8,302	8,346	0.9%
	%	0.5%	0.4%	0.5%	0.3%	0.5%	

Table B-1

SUMMER PEAK LOAD (MW) AND GROWTH RATES FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGIONS AND RTO
2009-2019

		METERED 2008	UNRESTRICTED 2008	NORMAL 2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Annual Growth Rate (10 yr)
AEP		23,730	23,834	24,160	23,682	23,817	24,419	25,109	25,469	25,669	25,897	26,082	26,268	26,426	26,554	1.2%
	%				-2.0%	0.6%	2.5%	2.8%	1.4%	0.8%	0.9%	0.7%	0.7%	0.6%	0.5%	
APS		8,428	8,432	8,410	8,538	8,705	8,949	9,125	9,257	9,378	9,487	9,580	9,683	9,775	9,889	1.5%
	%				1.5%	2.0%	2.8%	2.0%	1.4%	1.3%	1.2%	1.0%	1.1%	1.0%	1.2%	
COMED		20,948	20,976	23,230	22,472	22,803	23,725	24,848	25,552	26,052	26,434	26,766	27,053	27,366	27,722	2.1%
	%				-3.3%	1.5%	4.0%	4.7%	2.8%	2.0%	1.5%	1.3%	1.1%	1.2%	1.3%	
DAY		3,488	3,493	3,490	3,399	3,414	3,552	3,725	3,795	3,825	3,856	3,880	3,909	3,929	3,945	1.5%
	%				-2.6%	0.4%	4.0%	4.9%	1.9%	0.8%	0.8%	0.6%	0.7%	0.5%	0.4%	
DLCO		2,822	2,822	2,940	2,862	2,865	2,915	2,984	3,026	3,065	3,105	3,143	3,185	3,224	3,257	1.3%
	%				-2.7%	0.1%	1.7%	2.4%	1.4%	1.3%	1.3%	1.2%	1.3%	1.2%	1.0%	
DIVERSITY (-)					1,252	1,324	1,419	1,473	1,501	1,568	1,597	1,575	1,598	1,641	1,646	
PJM WESTERN		57,881	58,027	60,940	59,701	60,280	62,141	64,318	65,598	66,421	67,182	67,876	68,500	69,079	69,721	1.6%
	%				-2.0%	1.0%	3.1%	3.5%	2.0%	1.3%	1.1%	1.0%	0.9%	0.8%	0.9%	
DOM		19,051	19,060	19,230	18,982	19,264	19,921	20,675	21,140	21,518	21,895	22,294	22,721	23,130	23,603	2.2%
	%				-1.3%	1.5%	3.4%	3.8%	2.2%	1.8%	1.8%	1.8%	1.9%	1.8%	2.0%	
DIVERSITY (-)					3,876	3,847	3,957	3,936	4,002	4,023	4,070	4,178	4,148	4,104	4,219	
PJM RTO		130,100	130,792	136,315	134,428	136,038	140,132	144,613	147,442	149,497	151,410	153,189	155,042	156,822	158,617	1.7%
	%				-1.4%	1.2%	3.0%	3.2%	2.0%	1.4%	1.3%	1.2%	1.2%	1.1%	1.1%	

Note:
Normal 2008 and all forecast values are non-coincident as estimated by PJM staff.
Normal 2008 and all forecast values represent unrestricted peaks.

Table B-1 (Continued)

**SUMMER PEAK LOAD (MW) AND GROWTH RATES FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGIONS AND RTO
2020-2024**

		2020	2021	2022	2023	2024	Annual Growth Rate (15 yr)
AEP		26,692	26,804	26,914	27,016	27,097	0.9%
	%	0.5%	0.4%	0.4%	0.4%	0.3%	
APS		10,038	10,156	10,258	10,375	10,478	1.4%
	%	1.5%	1.2%	1.0%	1.1%	1.0%	
COMED		28,058	28,294	28,468	28,619	28,777	1.7%
	%	1.2%	0.8%	0.6%	0.5%	0.6%	
DAY		3,961	3,972	3,983	3,991	4,001	1.1%
	%	0.4%	0.3%	0.3%	0.2%	0.3%	
DLCO		3,292	3,320	3,347	3,375	3,401	1.2%
	%	1.1%	0.9%	0.8%	0.8%	0.8%	
DIVERSITY (-)		1,717	1,703	1,709	1,758	1,741	
PJM WESTERN		70,324	70,843	71,261	71,618	72,013	1.3%
	%	0.9%	0.7%	0.6%	0.5%	0.6%	
DOM		24,059	24,506	24,974	25,440	25,929	2.1%
	%	1.9%	1.9%	1.9%	1.9%	1.9%	
DIVERSITY (-)		4,368	4,431	4,525	4,319	4,347	
PJM RTO		160,357	161,954	163,433	165,006	166,581	1.4%
	%	1.1%	1.0%	0.9%	1.0%	1.0%	

Note:
Normal 2008 and all forecast values are non-coincident as estimated by PJM staff.
Normal 2008 and all forecast values represent unrestricted peaks.

Table B-2

**WINTER PEAK LOAD (MW) AND GROWTH RATES FOR
EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2008/09-2018/19**

		METERED 07/08	UNRESTRICTED 07/08	NORMAL 07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	Annual Growth Rate (10 yr)
AE		1,743	1,743	1,810	1,799	1,805	1,865	2,002	2,076	2,130	2,163	2,190	2,225	2,251	2,280	2.4%
	%				-0.6%	0.3%	3.3%	7.3%	3.7%	2.6%	1.5%	1.2%	1.6%	1.2%	1.3%	
BGE		5,690	5,690	5,920	5,986	6,017	6,118	6,191	6,238	6,292	6,357	6,427	6,501	6,572	6,637	1.0%
	%				1.1%	0.5%	1.7%	1.2%	0.8%	0.9%	1.0%	1.1%	1.2%	1.1%	1.0%	
DPL		3,232	3,232	3,310	3,307	3,301	3,356	3,448	3,529	3,582	3,631	3,673	3,724	3,775	3,825	1.5%
	%				-0.1%	-0.2%	1.7%	2.7%	2.3%	1.5%	1.4%	1.2%	1.4%	1.4%	1.3%	
JCPL		4,057	4,057	4,000	3,978	4,027	4,117	4,239	4,340	4,386	4,445	4,498	4,558	4,602	4,645	1.6%
	%				-0.5%	1.2%	2.2%	3.0%	2.4%	1.1%	1.3%	1.2%	1.3%	1.0%	0.9%	
METED		2,611	2,611	2,550	2,560	2,555	2,610	2,680	2,737	2,771	2,795	2,819	2,852	2,875	2,898	1.2%
	%				0.4%	-0.2%	2.2%	2.7%	2.1%	1.2%	0.9%	0.9%	1.2%	0.8%	0.8%	
PECO		6,519	6,519	6,610	6,526	6,438	6,531	6,685	6,793	6,858	6,916	6,982	7,056	7,112	7,167	0.9%
	%				-1.3%	-1.3%	1.4%	2.4%	1.6%	1.0%	0.8%	1.0%	1.1%	0.8%	0.8%	
PENLC		2,837	2,837	2,810	2,790	2,775	2,824	2,905	2,964	3,007	3,053	3,103	3,166	3,218	3,269	1.6%
	%				-0.7%	-0.5%	1.8%	2.9%	2.0%	1.5%	1.5%	1.6%	2.0%	1.6%	1.6%	
PEPCO		5,042	5,042	5,340	5,420	5,451	5,527	5,623	5,705	5,769	5,821	5,878	5,944	6,005	6,063	1.1%
	%				1.5%	0.6%	1.4%	1.7%	1.5%	1.1%	0.9%	1.0%	1.1%	1.0%	1.0%	
PL		7,163	7,163	7,210	7,182	7,159	7,242	7,369	7,467	7,517	7,573	7,619	7,682	7,723	7,759	0.8%
	%				-0.4%	-0.3%	1.2%	1.8%	1.3%	0.7%	0.7%	0.6%	0.8%	0.5%	0.5%	
PS		6,994	6,994	7,010	6,999	7,056	7,180	7,342	7,478	7,534	7,606	7,678	7,774	7,832	7,887	1.2%
	%				-0.2%	0.8%	1.8%	2.3%	1.9%	0.7%	1.0%	0.9%	1.3%	0.7%	0.7%	
RECO		245	245	235	237	239	241	243	245	247	249	251	253	255	257	0.8%
	%				0.9%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	
UGI		192	192	200	198	196	198	201	203	204	206	207	208	208	209	0.5%
	%				-1.0%	-1.0%	1.0%	1.5%	1.0%	0.5%	1.0%	0.5%	0.5%	0.0%	0.5%	
DIVERSITY (-)					538	497	466	463	539	490	480	491	567	576	597	
PJM MID-ATLANTIC		45,621	45,621	46,460	46,444	46,522	47,343	48,465	49,236	49,807	50,335	50,834	51,376	51,852	52,299	1.2%
	%				0.0%	0.2%	1.8%	2.4%	1.6%	1.2%	1.1%	1.0%	1.1%	0.9%	0.9%	
FE/GPU		9,341	9,341	9,290	9,248	9,296	9,490	9,762	9,968	10,097	10,223	10,357	10,503	10,616	10,729	1.5%
	%				-0.5%	0.5%	2.1%	2.9%	2.1%	1.3%	1.2%	1.3%	1.4%	1.1%	1.1%	
PLGRP		7,345	7,345	7,400	7,356	7,344	7,428	7,555	7,645	7,701	7,760	7,807	7,863	7,898	7,934	0.8%
	%				-0.6%	-0.2%	1.1%	1.7%	1.2%	0.7%	0.8%	0.6%	0.7%	0.4%	0.5%	

Note:
Normal 07/08 and all forecast values are non-coincident as estimated by PJM staff.
Normal 07/08 and all forecast values represent unrestricted peaks.

Table B-2 (Continued)

**WINTER PEAK LOAD (MW) AND GROWTH RATES FOR
EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2019/20-2023/24**

		19/20	**20/21**	**21/22**	**22/23**	**23/24**	**Annual Growth Rate (15 yr)**
AE		2,294	2,320	2,346	2,375	2,391	1.9%
	%	0.6%	1.1%	1.1%	1.2%	0.7%	
BGE		6,697	6,771	6,848	6,916	6,982	1.0%
	%	0.9%	1.1%	1.1%	1.0%	1.0%	
DPL		3,870	3,926	3,980	4,035	4,088	1.4%
	%	1.2%	1.4%	1.4%	1.4%	1.3%	
JCPL		4,664	4,715	4,760	4,810	4,839	1.3%
	%	0.4%	1.1%	1.0%	1.1%	0.6%	
METED		2,905	2,924	2,947	2,965	2,978	1.0%
	%	0.2%	0.7%	0.8%	0.6%	0.4%	
PECO		7,190	7,238	7,290	7,324	7,351	0.8%
	%	0.3%	0.7%	0.7%	0.5%	0.4%	
PENLC		3,306	3,355	3,406	3,454	3,495	1.5%
	%	1.1%	1.5%	1.5%	1.4%	1.2%	
PEPCO		6,117	6,177	6,244	6,306	6,363	1.1%
	%	0.9%	1.0%	1.1%	1.0%	0.9%	
PL		7,763	7,804	7,848	7,880	7,895	0.6%
	%	0.1%	0.5%	0.6%	0.4%	0.2%	
PS		7,912	7,981	8,050	8,122	8,157	1.0%
	%	0.3%	0.9%	0.9%	0.9%	0.4%	
RECO		259	261	263	265	267	0.8%
	%	0.8%	0.8%	0.8%	0.8%	0.8%	
UGI		209	209	210	210	210	0.4%
	%	0.0%	0.0%	0.5%	0.0%	0.0%	
DIVERSITY (-)		474	525	571	647	604	
PJM MID-ATLANTIC		52,712	53,156	53,621	54,015	54,412	1.1%
	%	0.8%	0.8%	0.9%	0.7%	0.7%	
FE/GPU		10,808	10,928	11,039	11,138	11,224	1.3%
	%	0.7%	1.1%	1.0%	0.9%	0.8%	
PLGRP		7,950	7,991	8,028	8,053	8,068	0.6%
	%	0.2%	0.5%	0.5%	0.3%	0.2%	

Table B-2

WINTER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO 2008/09-2018/19

		METERED 07/08	UNRESTRICTED 07/08	NORMAL 07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	Annual Growth Rate (10 yr)
AEP		24,215	24,215	23,230	22,974	22,885	23,154	23,611	23,956	24,014	24,158	24,321	24,549	24,644	24,729	0.7%
	%				-1.1%	-0.4%	1.2%	2.0%	1.5%	0.2%	0.6%	0.7%	0.9%	0.4%	0.3%	
APS		8,136	8,136	8,160	8,258	8,351	8,543	8,714	8,842	8,932	9,021	9,111	9,209	9,287	9,372	1.3%
	%				1.2%	1.1%	2.3%	2.0%	1.5%	1.0%	1.0%	1.0%	1.1%	0.8%	0.9%	
COMED		15,848	15,848	15,940	15,617	15,580	15,967	16,670	17,218	17,455	17,724	17,936	18,258	18,435	18,621	1.8%
	%				-2.0%	-0.2%	2.5%	4.4%	3.3%	1.4%	1.5%	1.2%	1.8%	1.0%	1.0%	
DAY		3,031	3,031	2,960	2,930	2,896	2,952	3,063	3,140	3,157	3,176	3,194	3,224	3,238	3,249	1.0%
	%				-1.0%	-1.2%	1.9%	3.8%	2.5%	0.5%	0.6%	0.6%	0.9%	0.4%	0.3%	
DLCO		2,137	2,137	2,170	2,138	2,126	2,137	2,173	2,196	2,199	2,215	2,235	2,269	2,283	2,302	0.7%
	%				-1.5%	-0.6%	0.5%	1.7%	1.1%	0.1%	0.7%	0.9%	1.5%	0.6%	0.8%	
DIVERSITY (-)					1,098	1,024	1,010	1,019	1,145	1,036	1,099	1,136	1,266	1,254	1,334	
PJM WESTERN		51,465	51,465	51,390	50,819	50,814	51,743	53,212	54,207	54,721	55,195	55,661	56,243	56,633	56,939	1.1%
	%				-1.1%	0.0%	1.8%	2.8%	1.9%	0.9%	0.9%	0.8%	1.0%	0.7%	0.5%	
DOM		17,028	17,028	16,760	16,677	16,773	17,089	17,621	18,037	18,302	18,551	18,831	19,117	19,403	19,710	1.7%
	%				-0.5%	0.6%	1.9%	3.1%	2.4%	1.5%	1.4%	1.5%	1.5%	1.5%	1.6%	
DIVERSITY (-)					1,377	1,359	1,413	1,489	1,424	1,486	1,453	1,479	1,612	1,588	1,508	
PJM RTO		111,724	111,724	113,185	112,563	112,750	114,762	117,809	120,056	121,344	122,628	123,847	125,124	126,300	127,440	1.2%
	%				-0.5%	0.2%	1.8%	2.7%	1.9%	1.1%	1.1%	1.0%	1.0%	0.9%	0.9%	

Note:
Normal 07/08 and all forecast values are non-coincident as estimated by PJM staff.
Normal 07/08 and all forecast values represent unrestricted peaks.

Table B-2 (Continued)

WINTER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO 2019/20-2023/24

		19/20	20/21	21/22	22/23	23/24	Annual Growth Rate (15 yr)
AEP		24,671	24,811	24,973	25,073	25,118	0.6%
	%	-0.2%	0.6%	0.7%	0.4%	0.2%	
APS		9,449	9,568	9,681	9,773	9,860	1.2%
	%	0.8%	1.3%	1.2%	1.0%	0.9%	
COMED		18,705	18,874	19,083	19,266	19,311	1.4%
	%	0.5%	0.9%	1.1%	1.0%	0.2%	
DAY		3,243	3,256	3,274	3,284	3,288	0.8%
	%	-0.2%	0.4%	0.6%	0.3%	0.1%	
DLCO		2,297	2,314	2,331	2,356	2,363	0.7%
	%	-0.2%	0.7%	0.7%	1.1%	0.3%	
DIVERSITY (-)		1,113	1,215	1,321	1,420	1,374	
PJM WESTERN		57,252	57,608	58,021	58,332	58,566	1.0%
	%	0.5%	0.6%	0.7%	0.5%	0.4%	
DOM		19,983	20,297	20,626	20,952	21,276	1.6%
	%	1.4%	1.6%	1.6%	1.6%	1.5%	
DIVERSITY (-)		1,589	1,524	1,589	1,660	1,655	
PJM RTO		128,358	129,537	130,679	131,639	132,599	1.1%
	%	0.7%	0.9%	0.9%	0.7%	0.7%	

Table B-3

SPRING (APRIL) PEAK LOAD (MW) FOR
EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2009-2024

	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
AE	1,513	1,543	1,652	1,790	1,878	1,941	1,972	2,003	2,030	2,071	2,097	2,136	2,159	2,184	2,202	2,233
BGE	4,909	4,965	5,033	5,095	5,160	5,267	5,376	5,436	5,480	5,594	5,671	5,812	5,909	5,980	6,051	6,142
DPL	2,655	2,664	2,694	2,779	2,852	2,910	2,945	2,973	3,008	3,063	3,115	3,195	3,234	3,257	3,295	3,359
JCPL	3,388	3,441	3,545	3,666	3,756	3,850	3,904	3,952	3,993	4,023	4,070	4,157	4,195	4,219	4,246	4,275
METED	2,249	2,253	2,293	2,370	2,421	2,457	2,476	2,489	2,507	2,537	2,559	2,567	2,574	2,590	2,614	2,632
PECO	5,645	5,595	5,616	5,786	5,886	6,005	6,093	6,086	6,113	6,174	6,221	6,367	6,435	6,357	6,376	6,399
PENLC	2,460	2,448	2,498	2,579	2,627	2,679	2,722	2,770	2,815	2,861	2,907	2,961	3,003	3,040	3,083	3,116
PEPCO	4,582	4,621	4,594	4,664	4,745	4,801	4,907	4,887	4,906	4,949	5,017	5,119	5,222	5,166	5,215	5,255
PL	5,815	5,807	5,900	6,047	6,151	6,217	6,249	6,309	6,341	6,385	6,419	6,461	6,488	6,507	6,536	6,558
PS	6,509	6,581	6,634	6,822	6,952	7,070	7,202	7,207	7,240	7,351	7,416	7,557	7,632	7,617	7,630	7,742
RECO	225	226	226	228	230	231	233	235	237	238	240	242	244	245	247	249
UGI	154	153	155	159	161	163	163	163	164	165	165	165	165	165	165	166
DIVERSITY (-)	2,180	2,170	1,976	1,731	1,728	1,885	2,087	2,035	1,991	1,661	1,673	2,067	1,989	2,039	1,998	1,587
PJM MID-ATLANTIC	37,924	38,127	38,864	40,254	41,091	41,706	42,155	42,475	42,843	43,750	44,224	44,672	45,271	45,288	45,662	46,539
FE/GPU	7,770	7,849	8,046	8,311	8,577	8,750	8,841	8,947	9,059	9,173	9,335	9,483	9,580	9,631	9,708	9,846
PLGRP	5,767	5,780	5,882	6,041	6,152	6,214	6,258	6,303	6,354	6,412	6,454	6,480	6,508	6,539	6,561	6,612

Table B-3

SPRING (APRIL) PEAK LOAD (MW) FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2009-2024

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
AEP	19,235	19,166	19,458	20,040	20,342	20,553	20,659	20,846	20,957	21,086	21,179	21,306	21,373	21,455	21,563	21,578
APS	6,824	6,918	7,074	7,251	7,360	7,461	7,507	7,578	7,642	7,717	7,799	7,899	7,965	8,045	8,141	8,221
COMED	13,631	13,739	14,258	15,188	15,777	16,099	16,299	16,537	16,708	17,122	17,373	17,505	17,673	17,768	17,867	18,270
DAY	2,466	2,440	2,495	2,630	2,698	2,725	2,747	2,755	2,769	2,790	2,794	2,818	2,827	2,821	2,825	2,830
DLCO	1,967	1,955	1,948	1,992	2,025	2,044	2,081	2,090	2,100	2,148	2,170	2,198	2,233	2,211	2,231	2,272
DIVERSITY (-)	1,864	1,698	1,842	1,865	1,908	2,036	1,912	2,104	2,039	2,117	2,203	2,118	2,139	2,161	2,138	2,329
PJM WESTERN	42,259	42,520	43,391	45,236	46,294	46,846	47,381	47,702	48,137	48,746	49,112	49,608	49,932	50,139	50,489	50,842
DOM	13,268	13,398	13,677	14,181	14,543	14,850	15,073	15,297	15,513	15,839	16,180	16,534	16,884	17,083	17,393	17,751
DIVERSITY (-)	1,599	1,488	1,260	1,745	1,809	2,150	1,891	1,380	1,382	1,994	1,886	2,185	2,721	1,533	1,724	2,192
PJM RTO	91,852	92,557	94,672	97,926	100,119	101,252	102,718	104,094	105,111	106,341	107,630	108,629	109,366	110,977	111,820	112,940

Table B-4

FALL (OCTOBER) PEAK LOAD (MW) FOR
EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2009-2024

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
AE	1,559	1,623	1,799	1,917	2,007	2,046	2,079	2,107	2,155	2,206	2,236	2,249	2,270	2,297	2,336	2,392
BGE	4,678	4,767	4,891	5,036	5,088	5,168	5,245	5,278	5,440	5,583	5,672	5,716	5,782	5,867	6,004	6,147
DPL	2,514	2,545	2,635	2,758	2,819	2,859	2,892	2,931	2,995	3,065	3,115	3,157	3,203	3,255	3,320	3,391
JCPL	3,532	3,605	3,736	3,955	4,037	4,107	4,159	4,162	4,266	4,364	4,415	4,450	4,444	4,485	4,576	4,670
METED	2,101	2,141	2,212	2,292	2,334	2,360	2,371	2,390	2,426	2,458	2,476	2,478	2,480	2,501	2,529	2,563
PECO	5,461	5,520	5,679	5,927	6,008	6,052	6,089	6,121	6,235	6,364	6,407	6,393	6,409	6,426	6,511	6,616
PENLC	2,390	2,427	2,511	2,593	2,627	2,661	2,700	2,753	2,818	2,883	2,917	2,937	2,973	3,025	3,079	3,133
PEPCO	4,617	4,653	4,671	4,874	4,921	4,961	4,984	4,952	5,070	5,183	5,232	5,245	5,269	5,272	5,380	5,489
PL	5,508	5,574	5,707	5,836	5,923	5,950	5,983	6,025	6,091	6,151	6,192	6,172	6,184	6,224	6,270	6,320
PS	6,863	6,919	7,084	7,400	7,503	7,593	7,647	7,617	7,766	7,937	8,011	8,031	8,020	8,058	8,185	8,358
RECO	244	245	247	259	262	263	263	260	268	273	275	273	273	272	278	284
UGI	149	149	153	156	159	160	160	161	162	163	163	162	162	163	164	164
DIVERSITY (-)	1,206	1,187	1,181	1,309	1,376	1,396	1,373	1,292	1,392	1,420	1,440	1,370	1,316	1,395	1,431	1,464
PJM MID-ATLANTIC	38,410	38,981	40,144	41,694	42,312	42,784	43,199	43,465	44,300	45,210	45,671	45,893	46,153	46,450	47,201	48,063
FE/GPU	7,838	7,988	8,270	8,556	8,739	8,872	8,986	9,060	9,252	9,412	9,525	9,616	9,615	9,709	9,918	10,059
PLGRP	5,623	5,699	5,843	5,965	6,047	6,072	6,116	6,178	6,229	6,273	6,306	6,305	6,328	6,381	6,415	6,440

Table B-4

FALL (OCTOBER) PEAK LOAD (MW) FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2009-2024

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
AEP	18,398	18,531	19,007	19,624	19,793	19,928	19,974	20,029	20,249	20,440	20,537	20,518	20,496	20,583	20,748	20,948
APS	6,473	6,613	6,796	6,950	7,040	7,101	7,139	7,218	7,306	7,424	7,500	7,525	7,585	7,690	7,797	7,929
COMED	13,464	13,828	14,586	15,551	15,958	16,276	16,491	16,629	16,996	17,340	17,585	17,719	17,799	17,863	18,102	18,341
DAY	2,347	2,382	2,501	2,637	2,675	2,693	2,699	2,705	2,741	2,773	2,783	2,772	2,767	2,773	2,796	2,827
DLCO	1,881	1,886	1,916	1,982	2,007	2,030	2,049	2,057	2,102	2,149	2,175	2,170	2,180	2,188	2,223	2,275
DIVERSITY (-)	985	1,044	990	1,367	1,367	1,434	1,344	1,190	1,391	1,578	1,627	1,530	1,414	1,317	1,492	1,803
PJM WESTERN	41,578	42,196	43,816	45,377	46,106	46,594	47,008	47,448	48,003	48,548	48,953	49,174	49,413	49,780	50,174	50,517
DOM	13,093	13,278	13,789	14,475	14,746	15,011	15,216	15,363	15,819	16,186	16,507	16,736	16,955	17,274	17,706	18,126
DIVERSITY (-)	1,312	1,314	1,506	1,539	1,505	1,527	1,452	1,798	1,740	1,656	1,703	1,808	1,860	2,185	1,990	1,851
PJM RTO	91,769	93,141	96,243	100,007	101,659	102,862	103,971	104,478	106,382	108,288	109,428	109,995	110,661	111,319	113,091	114,855

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 2009	1,797	5,986	3,307	3,978	2,560	6,526	2,790	5,420	7,182	6,999	230	198	529	46,444
Feb 2009	1,732	5,757	3,205	3,794	2,504	6,302	2,730	5,222	6,951	6,749	220	189	439	44,916
Mar 2009	1,578	5,224	2,881	3,552	2,400	5,911	2,612	4,688	6,380	6,476	216	171	1,726	40,363
Apr 2009	1,513	4,909	2,655	3,388	2,249	5,645	2,460	4,582	5,815	6,509	225	154	2,180	37,924
May 2009	1,805	5,633	2,964	4,450	2,380	6,537	2,366	5,536	5,758	8,294	326	146	1,800	44,395
Jun 2009	2,363	6,622	3,636	5,694	2,731	7,936	2,692	6,463	6,712	9,987	395	177	412	54,996
Jul 2009	2,692	7,303	3,972	6,357	2,866	8,455	2,786	6,960	7,106	10,858	435	190	359	59,621
Aug 2009	2,563	6,930	3,828	5,745	2,752	8,102	2,721	6,646	6,805	10,035	388	180	196	56,499
Sep 2009	2,173	6,241	3,307	5,064	2,467	7,099	2,558	6,027	6,256	9,046	338	165	827	49,914
Oct 2009	1,559	4,678	2,514	3,532	2,101	5,461	2,390	4,617	5,508	6,863	244	149	1,206	38,410
Nov 2009	1,549	4,836	2,659	3,534	2,214	5,610	2,513	4,467	5,990	6,447	221	167	470	39,737
Dec 2009	1,801	5,688	3,124	4,022	2,487	6,308	2,749	5,174	6,835	7,021	239	194	417	45,225

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	DIVERSITY	MID-ATLANTIC
Jan 2010	1,805	6,017	3,301	4,027	2,555	6,438	2,775	5,451	7,159	7,056	232	196	490	46,522
Feb 2010	1,745	5,817	3,209	3,854	2,505	6,231	2,720	5,284	6,968	6,827	221	188	394	45,175
Mar 2010	1,614	5,300	2,904	3,637	2,394	5,898	2,589	4,767	6,355	6,572	218	170	1,594	40,824
Apr 2010	1,543	4,965	2,664	3,441	2,253	5,595	2,448	4,621	5,807	6,581	226	153	2,170	38,127
May 2010	1,843	5,705	2,966	4,530	2,375	6,455	2,357	5,544	5,743	8,381	328	145	1,777	44,595
Jun 2010	2,423	6,775	3,673	5,847	2,763	7,927	2,702	6,565	6,756	10,187	401	176	487	55,708
Jul 2010	2,761	7,446	4,002	6,504	2,906	8,459	2,806	7,026	7,155	11,022	441	191	378	60,341
Aug 2010	2,643	7,102	3,877	5,899	2,803	8,157	2,749	6,739	6,873	10,232	394	181	50	57,599
Sep 2010	2,232	6,355	3,321	5,153	2,497	7,092	2,577	6,076	6,292	9,161	341	165	804	50,458
Oct 2010	1,623	4,767	2,545	3,605	2,141	5,520	2,427	4,653	5,574	6,919	245	149	1,187	38,981
Nov 2010	1,609	4,934	2,697	3,623	2,259	5,670	2,555	4,517	6,076	6,556	223	168	428	40,459
Dec 2010	1,854	5,760	3,140	4,108	2,531	6,355	2,794	5,213	6,898	7,148	241	196	396	45,842

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	DIVERSITY	MID-ATLANTIC
Jan 2011	1,865	6,118	3,356	4,117	2,610	6,531	2,824	5,527	7,242	7,180	234	198	459	47,343
Feb 2011	1,805	5,911	3,260	3,940	2,555	6,313	2,766	5,351	7,048	6,949	223	190	390	45,921
Mar 2011	1,666	5,334	2,906	3,726	2,424	5,868	2,628	4,746	6,429	6,603	219	171	1,241	41,479
Apr 2011	1,652	5,033	2,694	3,545	2,293	5,616	2,498	4,594	5,900	6,634	226	155	1,976	38,864
May 2011	1,982	5,869	3,046	4,697	2,450	6,616	2,419	5,647	5,920	8,584	337	148	1,619	46,096
Jun 2011	2,584	7,007	3,791	6,060	2,844	8,132	2,766	6,687	6,913	10,469	413	180	436	57,410
Jul 2011	2,980	7,668	4,138	6,717	2,995	8,681	2,877	7,141	7,319	11,292	451	195	427	62,027
Aug 2011	2,856	7,330	4,010	6,126	2,886	8,376	2,822	6,866	7,045	10,545	406	185	0	59,453
Sep 2011	2,417	6,499	3,411	5,297	2,562	7,230	2,640	6,146	6,398	9,344	347	167	599	51,859
Oct 2011	1,799	4,891	2,635	3,736	2,212	5,679	2,511	4,671	5,707	7,084	247	153	1,181	40,144
Nov 2011	1,755	5,027	2,783	3,753	2,325	5,829	2,640	4,594	6,204	6,728	225	170	408	41,625
Dec 2011	1,995	5,853	3,233	4,234	2,603	6,506	2,876	5,301	7,035	7,319	243	198	449	46,947

Table B-5

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

	AEP	APS	COMED	DAY	DLCO	WESTERN DIVERSITY	PJM WESTERN	DOM	RTO DIVERSITY	PJM RTO
Jan 2009	22,974	8,258	15,366	2,930	2,137	846	50,819	16,677	1,377	112,563
Feb 2009	22,348	7,986	14,911	2,824	2,075	743	49,401	16,039	2,060	108,296
Mar 2009	20,731	7,364	13,971	2,617	1,988	1,342	45,329	14,250	1,226	98,716
Apr 2009	19,235	6,824	13,631	2,466	1,967	1,864	42,259	13,268	1,599	91,852
May 2009	19,690	6,796	15,999	2,679	2,243	1,761	45,646	15,090	2,971	102,160
Jun 2009	22,763	8,117	20,642	3,206	2,724	1,292	56,160	17,752	3,674	125,234
Jul 2009	23,682	8,538	22,472	3,399	2,862	1,252	59,701	18,982	3,876	134,428
Aug 2009	23,236	8,189	21,356	3,289	2,724	1,202	57,592	18,270	4,864	127,497
Sep 2009	21,366	7,567	18,589	3,001	2,500	1,362	51,661	16,242	2,996	114,821
Oct 2009	18,398	6,473	13,464	2,347	1,881	985	41,578	13,093	1,312	91,769
Nov 2009	19,578	6,968	13,779	2,463	1,914	676	44,026	13,300	607	96,456
Dec 2009	22,030	8,016	15,580	2,801	2,124	613	49,938	15,669	1,468	109,364
	AEP	**APS**	**COMED**	**DAY**	**DLCO**	**DIVERSITY**	**WESTERN**	**DOM**	**DIVERSITY**	**PJM RTO**
Jan 2010	22,885	8,351	15,429	2,896	2,126	873	50,814	16,773	1,359	112,750
Feb 2010	22,318	8,094	14,988	2,794	2,065	760	49,499	16,195	2,234	108,635
Mar 2010	20,598	7,455	14,076	2,566	1,977	1,206	45,466	14,377	1,131	99,536
Apr 2010	19,166	6,918	13,739	2,440	1,955	1,698	42,520	13,398	1,488	92,557
May 2010	19,594	6,925	16,159	2,650	2,224	1,670	45,882	15,218	3,123	102,572
Jun 2010	22,942	8,294	20,876	3,209	2,728	1,426	56,623	18,029	3,939	126,421
Jul 2010	23,817	8,705	22,803	3,414	2,865	1,324	60,280	19,264	3,847	136,038
Aug 2010	23,443	8,372	21,775	3,315	2,743	1,230	58,418	18,638	5,439	129,216
Sep 2010	21,433	7,687	18,868	3,002	2,496	1,266	52,220	16,451	3,308	115,821
Oct 2010	18,531	6,613	13,828	2,382	1,886	1,044	42,196	13,278	1,314	93,141
Nov 2010	19,810	7,129	14,133	2,512	1,924	649	44,859	13,556	603	98,271
Dec 2010	22,190	8,179	15,967	2,844	2,136	712	50,604	15,912	1,281	111,077
	AEP	**APS**	**COMED**	**DAY**	**DLCO**	**DIVERSITY**	**WESTERN**	**DOM**	**DIVERSITY**	**PJM RTO**
Jan 2011	23,154	8,543	15,878	2,952	2,137	921	51,743	17,089	1,413	114,762
Feb 2011	22,490	8,276	15,427	2,849	2,074	912	50,204	16,461	2,028	110,558
Mar 2011	20,787	7,606	14,459	2,597	1,966	1,319	46,096	14,531	769	101,337
Apr 2011	19,458	7,074	14,258	2,495	1,948	1,842	43,391	13,677	1,260	94,672
May 2011	20,083	7,142	16,942	2,758	2,258	1,833	47,350	15,663	2,711	106,398
Jun 2011	23,470	8,540	21,750	3,330	2,768	1,482	58,376	18,560	4,164	130,182
Jul 2011	24,419	8,949	23,725	3,552	2,915	1,419	62,141	19,921	3,957	140,132
Aug 2011	24,035	8,622	22,738	3,456	2,796	1,027	60,620	19,262	5,775	133,560
Sep 2011	21,871	7,824	19,625	3,114	2,518	1,163	53,789	16,940	3,492	119,096
Oct 2011	19,007	6,796	14,586	2,501	1,916	990	43,816	13,789	1,506	96,243
Nov 2011	20,266	7,307	14,860	2,626	1,960	684	46,335	14,005	600	101,365
Dec 2011	22,693	8,368	16,670	2,959	2,173	684	52,179	16,424	1,425	114,125

Table B-6

MONTHLY PEAK FORECAST (MW)
FOR FE/GPU AND PLGRP

	FE/GPU	**PLGRP**
Jan 2009	9,248	7,356
Feb 2009	8,958	7,124
Mar 2009	8,298	6,385
Apr 2009	7,770	5,767
May 2009	8,823	5,773
Jun 2009	10,873	6,882
Jul 2009	11,866	7,266
Aug 2009	11,057	6,985
Sep 2009	9,897	6,404
Oct 2009	7,838	5,623
Nov 2009	8,192	6,133
Dec 2009	9,217	7,016
	FE/GPU	**PLGRP**
Jan 2010	9,296	7,344
Feb 2010	9,024	7,152
Mar 2010	8,384	6,385
Apr 2010	7,849	5,780
May 2010	8,936	5,782
Jun 2010	11,066	6,887
Jul 2010	12,052	7,305
Aug 2010	11,337	7,054
Sep 2010	10,056	6,448
Oct 2010	7,988	5,699
Nov 2010	8,374	6,236
Dec 2010	9,408	7,084
	FE/GPU	**PLGRP**
Jan 2011	9,490	7,428
Feb 2011	9,216	7,232
Mar 2011	8,549	6,472
Apr 2011	8,046	5,882
May 2011	9,277	5,967
Jun 2011	11,426	7,052
Jul 2011	12,421	7,471
Aug 2011	11,711	7,230
Sep 2011	10,353	6,565
Oct 2011	8,270	5,843
Nov 2011	8,657	6,372
Dec 2011	9,679	7,212

Note: FE/GPU contains JCPL, METED, and PENLC zones; PLGRP contains PL and UGI zones.

TABLE B-7

PJM MID-ATLANTIC REGION LOAD MANAGEMENT
PLACED UNDER PJM COORDINATION - SUMMER (MW)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
AE																
a) CONTRACTUALLY INTERRUPTIBLE	52	27	12	12	12	12	12	12	12	12	12	12	12	12	12	12
b) DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	52	27	12	12	12	12	12	12	12	12	12	12	12	12	12	12
BGE																
a) CONTRACTUALLY INTERRUPTIBLE	560	477	583	583	583	583	583	583	583	583	583	583	583	583	583	583
b) DIRECT CONTROL	213	213	213	213	213	213	213	213	213	213	213	213	213	213	213	213
TOTAL LOAD MANAGEMENT	773	690	796	796	796	796	796	796	796	796	796	796	796	796	796	796
DPL																
a) CONTRACTUALLY INTERRUPTIBLE	93	57	73	73	73	73	73	73	73	73	73	73	73	73	73	73
b) DIRECT CONTROL	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
TOTAL LOAD MANAGEMENT	119	83	99	99	99	99	99	99	99	99	99	99	99	99	99	99
JCPL																
a) CONTRACTUALLY INTERRUPTIBLE	167	90	62	62	62	62	62	62	62	62	62	62	62	62	62	62
b) DIRECT CONTROL	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48
TOTAL LOAD MANAGEMENT	215	138	110	110	110	110	110	110	110	110	110	110	110	110	110	110
METED																
a) CONTRACTUALLY INTERRUPTIBLE	68	93	77	77	77	77	77	77	77	77	77	77	77	77	77	77
b) DIRECT CONTROL	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
TOTAL LOAD MANAGEMENT	69	94	78	78	78	78	78	78	78	78	78	78	78	78	78	78
PECO																
a) CONTRACTUALLY INTERRUPTIBLE	352	237	236	236	236	236	236	236	236	236	236	236	236	236	236	236
b) DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	352	237	236	236	236	236	236	236	236	236	236	236	236	236	236	236
PENLC																
a) CONTRACTUALLY INTERRUPTIBLE	15	40	24	24	24	24	24	24	24	24	24	24	24	24	24	24
b) DIRECT CONTROL	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
TOTAL LOAD MANAGEMENT	23	48	32	32	32	32	32	32	32	32	32	32	32	32	32	32
PEPCO																
a) CONTRACTUALLY INTERRUPTIBLE	120	46	154	154	154	154	154	154	154	154	154	154	154	154	154	154
b) DIRECT CONTROL	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
TOTAL LOAD MANAGEMENT	131	57	165	165	165	165	165	165	165	165	165	165	165	165	165	165
PL																
a) CONTRACTUALLY INTERRUPTIBLE	282	290	312	312	312	312	312	312	312	312	312	312	312	312	312	312
b) DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	282	290	312	312	312	312	312	312	312	312	312	312	312	312	312	312
PS																
a) CONTRACTUALLY INTERRUPTIBLE	231	137	94	94	94	94	94	94	94	94	94	94	94	94	94	94
b) DIRECT CONTROL	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62
TOTAL LOAD MANAGEMENT	293	199	156	156	156	156	156	156	156	156	156	156	156	156	156	156
RECO																
a) CONTRACTUALLY INTERRUPTIBLE	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b) DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
UGI																
a) CONTRACTUALLY INTERRUPTIBLE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b) DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PJM MID-ATLANTIC																
a) CONTRACTUALLY INTERRUPTIBLE	1,942	1,494	1,627	1,627	1,627	1,627	1,627	1,627	1,627	1,627	1,627	1,627	1,627	1,627	1,627	1,627
b) DIRECT CONTROL	369	369	369	369	369	369	369	369	369	369	369	369	369	369	369	369
TOTAL LOAD MANAGEMENT	2,311	1,863	1,996	1,996	1,996	1,996	1,996	1,996	1,996	1,996	1,996	1,996	1,996	1,996	1,996	1,996

Notes: Forecast represents the amount of Demand Resources cleared in RPM auctions plus the 5-year average of Interruptible Load for Reliability/Active Load Management.
Winter load management is equal to Contractually Interruptible.

TABLE B-7

PJM WESTERN REGION AND PJM SOUTHERN REGION LOAD MANAGEMENT
PLACED UNDER PJM COORDINATION - SUMMER (MW)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
AEP																
a) CONTRACTUALLY INTERRUPTIBLE	545	535	550	550	550	550	550	550	550	550	550	550	550	550	550	550
b) DIRECT CONTROL	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32
TOTAL LOAD MANAGEMENT	577	567	582	582	582	582	582	582	582	582	582	582	582	582	582	582
APS																
a) CONTRACTUALLY INTERRUPTIBLE	189	92	137	137	137	137	137	137	137	137	137	137	137	137	137	137
b) DIRECT CONTROL	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
TOTAL LOAD MANAGEMENT	190	93	138	138	138	138	138	138	138	138	138	138	138	138	138	138
COMED																
a) CONTRACTUALLY INTERRUPTIBLE	532	395	498	498	498	498	498	498	498	498	498	498	498	498	498	498
b) DIRECT CONTROL	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
TOTAL LOAD MANAGEMENT	592	455	558	558	558	558	558	558	558	558	558	558	558	558	558	558
DAY																
a) CONTRACTUALLY INTERRUPTIBLE	19	17	32	32	32	32	32	32	32	32	32	32	32	32	32	32
b) DIRECT CONTROL	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
TOTAL LOAD MANAGEMENT	22	20	35	35	35	35	35	35	35	35	35	35	35	35	35	35
DLCO																
a) CONTRACTUALLY INTERRUPTIBLE	22	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
b) DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	22	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
PJM WESTERN																
a) CONTRACTUALLY INTERRUPTIBLE	1,307	1,060	1,238	1,238	1,238	1,238	1,238	1,238	1,238	1,238	1,238	1,238	1,238	1,238	1,238	1,238
b) DIRECT CONTROL	96	96	96	96	96	96	96	96	96	96	96	96	96	96	96	96
TOTAL LOAD MANAGEMENT	1,403	1,156	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,334
DOM																
a) CONTRACTUALLY INTERRUPTIBLE	28	23	126	126	126	126	126	126	126	126	126	126	126	126	126	126
b) DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	28	23	126	126	126	126	126	126	126	126	126	126	126	126	126	126
PJM RTO																
a) CONTRACTUALLY INTERRUPTIBLE	3,277	2,577	2,991	2,991	2,991	2,991	2,991	2,991	2,991	2,991	2,991	2,991	2,991	2,991	2,991	2,991
b) DIRECT CONTROL	465	465	465	465	465	465	465	465	465	465	465	465	465	465	465	465
TOTAL LOAD MANAGEMENT	3,742	3,042	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456

Notes: Forecast represents the amount of Demand Resources cleared in RPM auctions plus the 5-year average of Interruptible Load for Reliability/Active Load Management.
Winter load management is equal to Contractually Interruptible.

TABLE B-8

PJM MID-ATLANTIC REGION ENERGY EFFICIENCY PROGRAMS
AND SUM OF ENERGY EFFICIENCY AND LOAD MANAGEMENT - SUMMER (MW)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
AE																
a) ENERGY EFFICIENCY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b) LOAD MANAGEMENT	52	27	12	12	12	12	12	12	12	12	12	12	12	12	12	12
TOTAL	52	27	12	12	12	12	12	12	12	12	12	12	12	12	12	12
BGE																
a) ENERGY EFFICIENCY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b) LOAD MANAGEMENT	773	690	796	796	796	796	796	796	796	796	796	796	796	796	796	796
TOTAL	773	690	796	796	796	796	796	796	796	796	796	796	796	796	796	796
DPL																
a) ENERGY EFFICIENCY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b) LOAD MANAGEMENT	119	83	99	99	99	99	99	99	99	99	99	99	99	99	99	99
TOTAL	119	83	99	99	99	99	99	99	99	99	99	99	99	99	99	99
JCPL																
a) ENERGY EFFICIENCY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b) LOAD MANAGEMENT	215	138	110	110	110	110	110	110	110	110	110	110	110	110	110	110
TOTAL	215	138	110	110	110	110	110	110	110	110	110	110	110	110	110	110
METED																
a) ENERGY EFFICIENCY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b) LOAD MANAGEMENT	69	94	78	78	78	78	78	78	78	78	78	78	78	78	78	78
TOTAL	69	94	78	78	78	78	78	78	78	78	78	78	78	78	78	78
PECO																
a) ENERGY EFFICIENCY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b) LOAD MANAGEMENT	352	237	236	236	236	236	236	236	236	236	236	236	236	236	236	236
TOTAL	352	237	236	236	236	236	236	236	236	236	236	236	236	236	236	236
PENLC																
a) ENERGY EFFICIENCY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b) LOAD MANAGEMENT	23	48	32	32	32	32	32	32	32	32	32	32	32	32	32	32
TOTAL	23	48	32	32	32	32	32	32	32	32	32	32	32	32	32	32
PEPCO																
a) ENERGY EFFICIENCY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b) LOAD MANAGEMENT	131	57	165	165	165	165	165	165	165	165	165	165	165	165	165	165
TOTAL	131	57	165	165	165	165	165	165	165	165	165	165	165	165	165	165
PL																
a) ENERGY EFFICIENCY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b) LOAD MANAGEMENT	282	290	312	312	312	312	312	312	312	312	312	312	312	312	312	312
TOTAL	282	290	312	312	312	312	312	312	312	312	312	312	312	312	312	312
PS																
a) ENERGY EFFICIENCY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b) LOAD MANAGEMENT	293	199	156	156	156	156	156	156	156	156	156	156	156	156	156	156
TOTAL	293	199	156	156	156	156	156	156	156	156	156	156	156	156	156	156
RECO																
a) ENERGY EFFICIENCY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b) LOAD MANAGEMENT	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
UGI																
a) ENERGY EFFICIENCY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b) LOAD MANAGEMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PJM MID-ATLANTIC																
a) ENERGY EFFICIENCY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b) LOAD MANAGEMENT	2,311	1,863	1,996	1,996	1,996	1,996	1,996	1,996	1,996	1,996	1,996	1,996	1,996	1,996	1,996	1,996
TOTAL	2,311	1,863	1,996	1,996	1,996	1,996	1,996	1,996	1,996	1,996	1,996	1,996	1,996	1,996	1,996	1,996

Notes: Energy Efficiency values are impacts approved for use in PJM Reliability Pricing Model.
At time of publication, no Energy Efficiency programs have been approved as RPM resources.
Load Management detail appears in Table B-7.

TABLE B-8

PJM WESTERN REGION AND PJM SOUTHERN REGION ENERGY EFFICIENCY PROGRAMS AND SUM OF ENERGY EFFICIENCY AND LOAD MANAGEMENT - SUMMER (MW)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
AEP																
a) ENERGY EFFICIENCY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b) LOAD MANAGEMENT	577	567	582	582	582	582	582	582	582	582	582	582	582	582	582	582
TOTAL	577	567	582	582	582	582	582	582	582	582	582	582	582	582	582	582
APS																
a) ENERGY EFFICIENCY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b) LOAD MANAGEMENT	190	93	138	138	138	138	138	138	138	138	138	138	138	138	138	138
TOTAL	190	93	138	138	138	138	138	138	138	138	138	138	138	138	138	138
COMED																
a) ENERGY EFFICIENCY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b) LOAD MANAGEMENT	592	455	558	558	558	558	558	558	558	558	558	558	558	558	558	558
TOTAL	592	455	558	558	558	558	558	558	558	558	558	558	558	558	558	558
DAY																
a) ENERGY EFFICIENCY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b) LOAD MANAGEMENT	22	20	35	35	35	35	35	35	35	35	35	35	35	35	35	35
TOTAL	22	20	35	35	35	35	35	35	35	35	35	35	35	35	35	35
DLCO																
a) ENERGY EFFICIENCY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b) LOAD MANAGEMENT	22	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
TOTAL	22	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
PJM WESTERN																
a) ENERGY EFFICIENCY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b) LOAD MANAGEMENT	1,403	1,156	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,334
TOTAL	1,403	1,156	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,334
DOM																
a) ENERGY EFFICIENCY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b) LOAD MANAGEMENT	28	23	126	126	126	126	126	126	126	126	126	126	126	126	126	126
TOTAL	28	23	126	126	126	126	126	126	126	126	126	126	126	126	126	126
PJM RTO																
a) ENERGY EFFICIENCY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b) LOAD MANAGEMENT	3,742	3,042	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456
TOTAL	3,742	3,042	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456

Notes: Energy Efficiency values are impacts approved for use in PJM Reliability Pricing Model.
At time of publication, no Energy Efficiency programs have been approved as RPM resources.
Load Management detail appears in Table B-7.

Table B-9

ADJUSTMENTS TO SUMMER PEAK LOAD (MW) FOR EACH PJM ZONE AND RTO 2009-2024

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
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	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
COMED	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DAY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DLCO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DOM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PJM RTO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Notes: Adjustment values presented here are reflected in Tables B-1 through B-6 and Table B-10.
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
2009-2024

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
AE	2,588	2,657	2,868	3,006	3,123	3,183	3,229	3,279	3,324	3,370	3,407	3,442	3,486	3,526	3,555	3,592
BGE	7,017	7,162	7,371	7,480	7,597	7,733	7,880	8,005	8,144	8,282	8,432	8,589	8,723	8,851	8,990	9,152
DPL	3,819	3,849	3,980	4,132	4,236	4,318	4,389	4,462	4,543	4,619	4,707	4,789	4,876	4,955	5,045	5,131
JCPL	6,095	6,261	6,466	6,654	6,812	6,891	6,986	7,096	7,189	7,271	7,345	7,410	7,480	7,555	7,630	7,704
METED	2,747	2,787	2,872	2,959	3,022	3,066	3,097	3,129	3,160	3,183	3,210	3,238	3,258	3,282	3,298	3,319
PECO	8,129	8,135	8,345	8,567	8,680	8,775	8,872	8,958	9,049	9,132	9,197	9,259	9,321	9,368	9,416	9,464
PENLC	2,653	2,674	2,742	2,816	2,868	2,914	2,963	3,015	3,070	3,116	3,169	3,216	3,263	3,305	3,351	3,392
PEPCO	6,693	6,761	6,868	6,983	7,084	7,163	7,238	7,297	7,375	7,449	7,543	7,623	7,698	7,770	7,850	7,930
PL	6,826	6,873	7,030	7,207	7,324	7,399	7,463	7,528	7,587	7,643	7,692	7,732	7,771	7,806	7,840	7,879
PS	10,446	10,619	10,862	11,149	11,328	11,458	11,578	11,697	11,818	11,917	12,024	12,116	12,218	12,300	12,399	12,499
RECO	416	422	432	443	450	455	459	464	469	474	479	483	487	490	494	498
UGI	182	183	187	191	193	195	196	197	198	199	200	200	200	200	201	201
AEP	22,749	22,864	23,414	24,072	24,402	24,604	24,814	24,994	25,169	25,337	25,446	25,565	25,679	25,783	25,882	25,993
APS	8,202	8,371	8,601	8,784	8,912	9,025	9,129	9,217	9,326	9,420	9,528	9,658	9,775	9,883	10,001	10,110
COMED	21,617	21,886	22,763	23,863	24,530	24,996	25,361	25,673	25,960	26,269	26,602	26,917	27,134	27,301	27,467	27,631
DAY	3,236	3,253	3,385	3,547	3,619	3,651	3,679	3,703	3,729	3,748	3,765	3,779	3,791	3,802	3,811	3,821
DLCO	2,738	2,739	2,787	2,852	2,899	2,938	2,979	3,015	3,056	3,095	3,128	3,162	3,190	3,216	3,247	3,276
DOM	18,275	18,542	19,159	19,908	20,363	20,733	21,098	21,460	21,876	22,298	22,743	23,179	23,604	24,040	24,529	24,989
PJM RTO	134,428	136,038	140,132	144,613	147,442	149,497	151,410	153,189	155,042	156,822	158,617	160,357	161,954	163,433	165,006	166,581
Eastern MAAC	31,493	31,943	32,953	33,951	34,629	35,080	35,513	35,956	36,392	36,783	37,159	37,499	37,868	38,194	38,539	38,888
Southwest MAAC	13,710	13,923	14,239	14,463	14,681	14,896	15,118	15,302	15,519	15,731	15,975	16,212	16,421	16,621	16,840	17,082
MAAC and APS	65,813	66,754	68,624	70,371	71,629	72,575	73,479	74,344	75,252	76,075	76,933	77,755	78,556	79,291	80,070	80,871

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

YEAR	SPRING (WK 14-19)	SUMMER (WK 20-39)	FALL (WK 40-45)	WINTER (WK 46-13)
2009	16,998	24,167	16,598	21,197
2010	17,082	24,476	16,742	21,271
2011	17,394	25,055	17,123	21,613
2012	17,786	25,552	17,663	21,947
2013	18,041	25,952	17,917	22,210
2014	18,261	26,284	18,085	22,419
2015	18,435	26,602	18,240	22,620
2016	18,630	26,915	18,323	22,838
2017	18,796	27,253	18,640	23,037
2018	19,009	27,559	18,940	23,209
2019	19,144	27,879	19,132	23,392
2020	19,357	28,181	19,181	23,555
2021	19,504	28,466	19,290	23,763
2022	19,670	28,765	19,473	23,971
2023	19,848	29,043	19,748	24,102
2024	20,087	29,343	19,988	24,238

TABLE C-2

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

YEAR	SPRING (WK 14-19)	SUMMER (WK 20-39)	FALL (WK 40-45)	WINTER (WK 46-13)
2009	10,257	12,829	10,066	12,647
2010	10,293	12,935	10,190	12,619
2011	10,499	13,253	10,465	12,807
2012	10,808	13,598	10,772	13,087
2013	11,028	13,839	10,922	13,285
2014	11,172	14,011	11,009	13,440
2015	11,297	14,167	11,119	13,559
2016	11,414	14,302	11,230	13,684
2017	11,542	14,457	11,401	13,815
2018	11,676	14,586	11,519	13,928
2019	11,793	14,721	11,606	14,037
2020	11,882	14,848	11,657	14,122
2021	11,962	14,944	11,715	14,223
2022	12,052	15,047	11,824	14,323
2023	12,127	15,147	11,948	14,400
2024	12,261	15,253	12,044	14,476

TABLE C-3

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

YEAR	SPRING (WK 14-19)	SUMMER (WK 20-39)	FALL (WK 40-45)	WINTER (WK 46-13)
2009	18,792	32,520	19,878	22,617
2010	18,929	32,921	20,192	22,667
2011	19,505	33,991	20,775	23,105
2012	20,206	35,014	22,027	23,773
2013	20,708	35,721	22,439	24,252
2014	20,996	36,218	22,707	24,541
2015	21,323	36,663	22,860	24,818
2016	21,489	37,117	22,789	25,069
2017	21,723	37,559	23,378	25,343
2018	22,106	37,934	23,991	25,587
2019	22,350	38,380	24,251	25,821
2020	22,516	38,755	24,301	25,995
2021	22,737	39,117	24,389	26,218
2022	22,865	39,473	24,490	26,438
2023	23,108	39,824	24,884	26,633
2024	23,378	40,162	25,463	26,827

TABLE C-4

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

YEAR	SPRING (WK 14-19)	SUMMER (WK 20-39)	FALL (WK 40-45)	WINTER (WK 46-13)
2009	8,994	14,188	9,183	11,366
2010	9,119	14,404	9,315	11,454
2011	9,309	14,723	9,484	11,626
2012	9,507	14,915	9,802	11,785
2013	9,647	15,175	9,910	11,903
2014	9,784	15,392	10,027	12,026
2015	9,923	15,622	10,124	12,143
2016	10,054	15,791	10,173	12,276
2017	10,144	16,010	10,444	12,395
2018	10,362	16,204	10,669	12,520
2019	10,466	16,502	10,770	12,648
2020	10,620	16,753	10,862	12,776
2021	10,779	16,959	10,958	12,903
2022	10,867	17,122	11,052	13,042
2023	10,964	17,347	11,307	13,154
2024	11,174	17,631	11,529	13,279

TABLE C-5

PJM LOCATIONAL DELIVERABILITY AREAS
MID-ATLANTIC and APS: AE, APS, BGE, DPL, JCPL, METED, PECO, PENLC, PEPCO, PL, PS, RECO, and UGI
SEASONAL PEAKS - MW

YEAR	SPRING (WK 14-19)	SUMMER (WK 20-39)	FALL (WK 40-45)	WINTER (WK 46-13)
2009	44,615	67,942	44,622	54,545
2010	44,962	68,871	45,235	54,747
2011	45,739	70,839	46,640	55,744
2012	47,173	72,170	48,184	57,032
2013	48,084	73,444	48,961	57,928
2014	48,943	74,471	49,491	58,562
2015	49,657	75,753	49,915	59,181
2016	49,823	76,676	50,344	59,775
2017	50,393	77,520	51,197	60,414
2018	51,055	78,157	52,100	60,957
2019	51,604	79,007	52,598	61,476
2020	52,531	80,129	52,898	61,972
2021	53,050	80,932	53,242	62,525
2022	53,032	81,744	53,662	63,123
2023	53,597	82,483	54,512	63,579
2024	54,152	83,100	55,179	64,035

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Table D-1

SUMMER EXTREME WEATHER (90/10) PEAK LOAD
FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION (MW)
2009-2024

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
AE	2,846	2,921	3,145	3,292	3,417	3,479	3,532	3,582	3,629	3,684	3,725	3,763	3,806	3,844	3,881	3,922
BGE	7,538	7,712	7,934	8,047	8,163	8,296	8,456	8,619	8,774	8,931	9,087	9,241	9,411	9,571	9,723	9,873
DPL	4,170	4,202	4,340	4,499	4,620	4,715	4,798	4,880	4,955	5,039	5,140	5,250	5,344	5,434	5,515	5,605
JCPL	6,724	6,857	7,086	7,290	7,472	7,638	7,717	7,802	7,922	7,972	8,072	8,182	8,236	8,321	8,426	8,467
METED	2,963	3,004	3,093	3,186	3,255	3,294	3,328	3,360	3,394	3,425	3,455	3,477	3,501	3,522	3,543	3,568
PECO	8,881	8,878	9,102	9,326	9,472	9,581	9,679	9,766	9,858	9,933	10,021	10,095	10,157	10,210	10,260	10,305
PENLC	2,870	2,881	2,954	3,026	3,078	3,126	3,180	3,232	3,285	3,336	3,386	3,437	3,484	3,528	3,572	3,613
PEPCO	7,268	7,351	7,474	7,600	7,704	7,787	7,869	7,953	8,033	8,126	8,210	8,294	8,384	8,467	8,549	8,631
PL	7,355	7,403	7,552	7,732	7,867	7,958	8,036	8,070	8,130	8,193	8,254	8,321	8,346	8,374	8,401	8,447
PS	11,370	11,458	11,751	12,033	12,256	12,489	12,620	12,673	12,802	12,925	13,043	13,237	13,257	13,372	13,462	13,563
RECO	461	466	477	488	498	503	509	515	520	523	530	535	539	544	548	552
UGI	198	198	202	207	210	211	213	213	214	215	216	216	217	217	217	218
DIVERSITY (-)	192	198	153	310	122	137	189	75	67	387	89	182	135	147	115	45
PJM MID-ATLANTIC	62,452	63,133	64,957	66,416	67,890	68,940	69,748	70,590	71,449	71,915	73,050	73,866	74,547	75,257	75,982	76,719
FE/GPU	12,557	12,742	13,127	13,432	13,805	14,058	14,225	14,390	14,595	14,654	14,913	15,096	15,221	15,369	15,537	15,648
PLGRP	7,553	7,601	7,754	7,939	8,077	8,169	8,249	8,283	8,344	8,408	8,470	8,537	8,563	8,591	8,618	8,665

Table D-1

SUMMER EXTREME WEATHER (90/10) PEAK LOAD
FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2009-2024

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
AEP	24,518	24,669	25,331	25,974	26,383	26,611	26,908	27,118	27,265	27,446	27,606	27,788	27,898	28,010	28,086	28,187
APS	8,774	8,952	9,198	9,403	9,528	9,635	9,744	9,852	9,959	10,079	10,181	10,305	10,434	10,557	10,677	10,786
COMED	23,785	24,213	25,242	26,470	27,056	27,473	27,869	28,303	28,620	28,959	29,282	29,542	29,825	30,019	30,164	30,336
DAY	3,504	3,523	3,663	3,840	3,910	3,937	3,967	3,998	4,026	4,052	4,064	4,074	4,091	4,105	4,115	4,123
DLCO	3,007	3,007	3,053	3,126	3,171	3,207	3,249	3,292	3,339	3,384	3,411	3,442	3,475	3,504	3,542	3,561
DIVERSITY (-)	744	811	790	700	659	618	784	781	702	752	733	805	837	751	719	699
PJM WESTERN	62,844	63,553	65,697	68,113	69,389	70,245	70,953	71,782	72,507	73,168	73,811	74,346	74,886	75,444	75,865	76,294
DOM	19,372	19,703	20,367	21,146	21,625	21,994	22,386	22,812	23,241	23,706	24,168	24,614	25,111	25,591	26,079	26,573
DIVERSITY (-)	1,999	1,938	2,096	2,011	2,257	2,356	2,295	2,441	2,460	2,315	2,476	2,503	2,557	2,642	2,684	2,689
PJM RTO	142,669	144,451	148,925	153,664	156,647	158,823	160,792	162,743	164,737	166,474	168,553	170,323	171,987	173,650	175,242	176,897

Table D-2

WINTER EXTREME WEATHER (90/10) PEAK LOAD
FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION (MW)
2008/09- 2023/24

	08/09	**09/10**	**10/11**	**11/12**	**12/13**	**13/14**	**14/15**	**15/16**	**16/17**	**17/18**	**18/19**	**19/20**	**20/21**	**21/22**	**22/23**	**23/24**
AE	1,882	1,884	1,938	2,066	2,136	2,175	2,217	2,249	2,290	2,307	2,339	2,350	2,377	2,406	2,433	2,445
BGE	6,291	6,329	6,408	6,477	6,525	6,540	6,639	6,724	6,798	6,853	6,917	6,966	7,057	7,135	7,197	7,254
DPL	3,507	3,504	3,559	3,647	3,723	3,754	3,825	3,880	3,936	3,980	4,025	4,067	4,137	4,199	4,251	4,296
JCPL	4,117	4,159	4,240	4,355	4,463	4,466	4,562	4,619	4,678	4,713	4,767	4,772	4,832	4,877	4,924	4,948
METED	2,645	2,647	2,698	2,762	2,819	2,836	2,878	2,908	2,942	2,961	2,984	2,987	3,013	3,039	3,055	3,065
PECO	6,785	6,678	6,748	6,914	6,991	7,014	7,123	7,203	7,314	7,356	7,365	7,378	7,462	7,524	7,571	7,589
PENLC	2,874	2,863	2,909	2,985	3,045	3,071	3,133	3,193	3,260	3,303	3,355	3,387	3,449	3,505	3,550	3,584
PEPCO	5,702	5,739	5,811	5,909	5,992	6,012	6,107	6,181	6,269	6,304	6,368	6,408	6,493	6,578	6,642	6,679
PL	7,521	7,510	7,582	7,704	7,793	7,789	7,893	7,959	8,029	8,049	8,087	8,072	8,143	8,182	8,224	8,217
PS	7,180	7,229	7,334	7,478	7,639	7,625	7,756	7,831	7,922	7,972	8,054	8,052	8,127	8,195	8,257	8,294
RECO	242	244	246	248	250	252	254	256	258	260	262	264	266	268	271	273
UGI	207	205	207	210	212	211	214	215	217	217	217	217	218	219	219	219
DIVERSITY (-)	592	530	381	212	415	77	343	474	457	468	515	336	503	474	472	509
PJM MID-ATLANTIC	48,361	48,461	49,299	50,543	51,173	51,668	52,258	52,744	53,456	53,807	54,225	54,584	55,071	55,653	56,122	56,354
FE/GPU	9,617	9,635	9,815	10,078	10,307	10,373	10,573	10,689	10,826	10,955	11,067	11,133	11,254	11,362	11,465	11,565
PLGRP	7,725	7,711	7,789	7,914	8,005	8,000	8,107	8,173	8,239	8,266	8,303	8,289	8,354	8,386	8,431	8,436

Table D-2

WINTER EXTREME WEATHER (90/10) PEAK LOAD
FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO (MW)
2008/09- 2023/24

	08/09	**09/10**	**10/11**	**11/12**	**12/13**	**13/14**	**14/15**	**15/16**	**16/17**	**17/18**	**18/19**	**19/20**	**20/21**	**21/22**	**22/23**	**23/24**
AEP	24,709	24,550	24,730	25,118	25,471	25,438	25,804	25,903	26,091	26,128	26,231	26,210	26,384	26,528	26,592	26,584
APS	8,743	8,850	9,029	9,205	9,330	9,337	9,528	9,638	9,747	9,812	9,894	9,923	10,120	10,250	10,341	10,412
COMED	16,177	16,115	16,503	17,131	17,740	17,806	18,147	18,372	18,678	18,828	19,057	19,089	19,272	19,472	19,627	19,664
DAY	3,130	3,097	3,126	3,235	3,304	3,306	3,351	3,376	3,394	3,403	3,416	3,408	3,437	3,444	3,454	3,452
DLCO	2,226	2,214	2,220	2,237	2,272	2,255	2,284	2,301	2,333	2,343	2,368	2,353	2,374	2,392	2,409	2,415
DIVERSITY (-)	985	872	999	1,095	1,250	750	795	952	1,374	1,283	1,301	1,129	1,030	1,211	1,443	1,347
PJM WESTERN	54,000	53,954	54,609	55,831	56,867	57,392	58,319	58,638	58,869	59,231	59,665	59,854	60,557	60,875	60,980	61,180
DOM	17,916	17,999	18,313	18,817	19,255	19,392	19,776	20,097	20,405	20,660	20,975	21,223	21,605	21,960	22,280	22,570
DIVERSITY (-)	887	860	755	822	736	1,798	1,168	1,097	1,159	985	1,055	1,882	1,215	1,353	1,271	1,125
PJM RTO	119,390	119,554	121,466	124,369	126,559	126,654	129,185	130,382	131,571	132,713	133,810	133,779	136,018	137,135	138,111	138,979

Table E-1

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION 2009-2019

		ESTIMATED 2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Annual Growth Rate (10 yr)
AE		11,435	11,503	11,765	12,577	13,366	13,861	14,190	14,408	14,659	14,841	15,055	15,229	2.8%
	%		0.6%	2.3%	6.9%	6.3%	3.7%	2.4%	1.5%	1.7%	1.2%	1.4%	1.2%	
BGE		34,402	34,928	35,520	36,442	37,054	37,360	37,944	38,557	39,308	39,824	40,450	41,052	1.6%
	%		1.5%	1.7%	2.6%	1.7%	0.8%	1.6%	1.6%	1.9%	1.3%	1.6%	1.5%	
DPL		19,094	19,136	19,230	19,735	20,397	20,788	21,161	21,453	21,805	22,062	22,401	22,736	1.7%
	%		0.2%	0.5%	2.6%	3.4%	1.9%	1.8%	1.4%	1.6%	1.2%	1.5%	1.5%	
JCPL		24,629	25,012	25,571	26,445	27,469	28,020	28,503	28,923	29,426	29,744	30,122	30,438	2.0%
	%		1.6%	2.2%	3.4%	3.9%	2.0%	1.7%	1.5%	1.7%	1.1%	1.3%	1.0%	
METED		16,142	15,966	16,153	16,638	17,191	17,491	17,759	17,958	18,201	18,332	18,514	18,634	1.6%
	%		-1.1%	1.2%	3.0%	3.3%	1.7%	1.5%	1.1%	1.4%	0.7%	1.0%	0.6%	
PECO		41,992	41,075	40,962	42,061	43,377	43,954	44,557	45,056	45,684	46,047	46,515	46,876	1.3%
	%		-2.2%	-0.3%	2.7%	3.1%	1.3%	1.4%	1.1%	1.4%	0.8%	1.0%	0.8%	
PENLC		18,394	18,149	18,252	18,778	19,426	19,786	20,197	20,604	21,096	21,453	21,882	22,275	2.1%
	%		-1.3%	0.6%	2.9%	3.5%	1.9%	2.1%	2.0%	2.4%	1.7%	2.0%	1.8%	
PEPCO		32,230	33,063	33,391	33,951	34,655	35,006	35,404	35,757	36,241	36,518	36,913	37,286	1.2%
	%		2.6%	1.0%	1.7%	2.1%	1.0%	1.1%	1.0%	1.4%	0.8%	1.1%	1.0%	
PL		42,153	41,629	41,822	42,723	43,879	44,434	44,980	45,392	45,898	46,127	46,483	46,722	1.2%
	%		-1.2%	0.5%	2.2%	2.7%	1.3%	1.2%	0.9%	1.1%	0.5%	0.8%	0.5%	
PS		47,535	48,556	49,328	50,625	52,109	52,845	53,576	54,201	54,988	55,435	55,999	56,459	1.5%
	%		2.1%	1.6%	2.6%	2.9%	1.4%	1.4%	1.2%	1.5%	0.8%	1.0%	0.8%	
RECO		1,577	1,587	1,609	1,650	1,694	1,717	1,741	1,761	1,785	1,799	1,819	1,833	1.5%
	%		0.6%	1.4%	2.5%	2.7%	1.4%	1.4%	1.1%	1.4%	0.8%	1.1%	0.8%	
UGI		1,071	1,056	1,057	1,078	1,106	1,121	1,129	1,138	1,147	1,150	1,154	1,156	0.9%
	%		-1.4%	0.1%	2.0%	2.6%	1.4%	0.7%	0.8%	0.8%	0.3%	0.3%	0.2%	
PJM MID-ATLANTIC		290,655	291,660	294,660	302,703	311,723	316,383	321,141	325,208	330,238	333,332	337,307	340,696	1.6%
	%		0.3%	1.0%	2.7%	3.0%	1.5%	1.5%	1.3%	1.5%	0.9%	1.2%	1.0%	
FE/GPU		59,166	59,127	59,976	61,861	64,086	65,297	66,459	67,485	68,723	69,529	70,518	71,347	1.9%
	%		-0.1%	1.4%	3.1%	3.6%	1.9%	1.8%	1.5%	1.8%	1.2%	1.4%	1.2%	
PLGRP		43,224	42,685	42,879	43,801	44,985	45,555	46,109	46,530	47,045	47,277	47,637	47,878	1.2%
	%		-1.2%	0.5%	2.2%	2.7%	1.3%	1.2%	0.9%	1.1%	0.5%	0.8%	0.5%	

Note: Estimated 2008 includes weather-normalized data through August.

Table E-1 (Continued)

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION 2020-2024

		2020	2021	2022	2023	2024	Annual Growth Rate (15 yr)
AE		15,445	15,577	15,747	15,906	16,122	2.3%
	%	1.4%	0.9%	1.1%	1.0%	1.4%	
BGE		41,814	42,335	42,985	43,613	44,357	1.6%
	%	1.9%	1.2%	1.5%	1.5%	1.7%	
DPL		23,167	23,443	23,792	24,139	24,560	1.7%
	%	1.9%	1.2%	1.5%	1.5%	1.7%	
JCPL		30,851	31,093	31,420	31,716	32,108	1.7%
	%	1.4%	0.8%	1.1%	0.9%	1.2%	
METED		18,851	18,933	19,053	19,157	19,328	1.3%
	%	1.2%	0.4%	0.6%	0.5%	0.9%	
PECO		47,400	47,588	47,877	48,121	48,499	1.1%
	%	1.1%	0.4%	0.6%	0.5%	0.8%	
PENLC		22,757	23,075	23,442	23,784	24,194	1.9%
	%	2.2%	1.4%	1.6%	1.5%	1.7%	
PEPCO		37,791	38,073	38,467	38,833	39,309	1.2%
	%	1.4%	0.7%	1.0%	1.0%	1.2%	
PL		47,173	47,278	47,504	47,678	48,003	1.0%
	%	1.0%	0.2%	0.5%	0.4%	0.7%	
PS		57,173	57,503	58,008	58,440	59,027	1.3%
	%	1.3%	0.6%	0.9%	0.7%	1.0%	
RECO		1,857	1,871	1,888	1,901	1,919	1.3%
	%	1.3%	0.8%	0.9%	0.7%	0.9%	
UGI		1,164	1,162	1,164	1,165	1,168	0.7%
	%	0.7%	-0.2%	0.2%	0.1%	0.3%	
PJM MID-ATLANTIC		345,443	347,931	351,347	354,453	358,594	1.4%
	%	1.4%	0.7%	1.0%	0.9%	1.2%	
FE/GPU		72,459	73,101	73,915	74,657	75,630	1.7%
	%	1.6%	0.9%	1.1%	1.0%	1.3%	
PLGRP		48,337	48,440	48,668	48,843	49,171	0.9%
	%	1.0%	0.2%	0.5%	0.4%	0.7%	

Table E-1

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2009-2019

		ESTIMATED 2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Annual Growth Rate (10 yr)
AEP		144,108	142,006	142,454	145,290	149,273	150,628	151,951	153,121	154,634	155,116	156,021	156,495	1.0%
	%		-1.5%	0.3%	2.0%	2.7%	0.9%	0.9%	0.8%	1.0%	0.3%	0.6%	0.3%	
APS		48,864	49,309	50,176	51,468	52,674	53,234	53,882	54,420	55,141	55,553	56,155	56,686	1.4%
	%		0.9%	1.8%	2.6%	2.3%	1.1%	1.2%	1.0%	1.3%	0.7%	1.1%	0.9%	
COMED		104,322	102,616	104,175	109,033	115,402	118,725	121,300	123,347	125,647	127,045	128,730	130,337	2.4%
	%		-1.6%	1.5%	4.7%	5.8%	2.9%	2.2%	1.7%	1.9%	1.1%	1.3%	1.2%	
DAY		18,655	17,979	18,014	18,733	19,718	20,085	20,312	20,484	20,710	20,799	20,920	20,967	1.5%
	%		-3.6%	0.2%	4.0%	5.3%	1.9%	1.1%	0.8%	1.1%	0.4%	0.6%	0.2%	
DLCO		14,857	14,615	14,582	14,814	15,190	15,368	15,587	15,792	16,047	16,211	16,412	16,573	1.3%
	%		-1.6%	-0.2%	1.6%	2.5%	1.2%	1.4%	1.3%	1.6%	1.0%	1.2%	1.0%	
PJM WESTERN		330,805	326,525	329,401	339,338	352,257	358,040	363,032	367,164	372,179	374,724	378,238	381,058	1.6%
	%		-1.3%	0.9%	3.0%	3.8%	1.6%	1.4%	1.1%	1.4%	0.7%	0.9%	0.7%	
DOM		94,738	94,051	95,372	98,382	102,277	104,324	106,246	108,048	110,327	111,987	114,075	116,153	2.1%
	%		-0.7%	1.4%	3.2%	4.0%	2.0%	1.8%	1.7%	2.1%	1.5%	1.9%	1.8%	
PJM RTO		716,198	712,236	719,433	740,423	766,257	778,747	790,419	800,420	812,744	820,043	829,620	837,907	1.6%
	%		-0.6%	1.0%	2.9%	3.5%	1.6%	1.5%	1.3%	1.5%	0.9%	1.2%	1.0%	

Note: Estimated 2008 includes weather-normalized data through August.

Table E-1 (Continued)

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO 2020-2024

		2020	2021	2022	2023	2024	Annual Growth Rate (15 yr)
AEP		157,804	158,006	158,655	159,115	159,966	0.8%
	%	0.8%	0.1%	0.4%	0.3%	0.5%	
APS		57,539	58,017	58,673	59,295	60,082	1.3%
	%	1.5%	0.8%	1.1%	1.1%	1.3%	
COMED		132,435	133,386	134,446	135,214	136,311	1.9%
	%	1.6%	0.7%	0.8%	0.6%	0.8%	
DAY		21,143	21,167	21,245	21,284	21,360	1.2%
	%	0.8%	0.1%	0.4%	0.2%	0.4%	
DLCO		16,802	16,912	17,063	17,198	17,374	1.2%
	%	1.4%	0.7%	0.9%	0.8%	1.0%	
PJM WESTERN		385,723	387,488	390,082	392,106	395,093	1.3%
	%	1.2%	0.5%	0.7%	0.5%	0.8%	
DOM		118,677	120,539	122,817	125,060	127,671	2.1%
	%	2.2%	1.6%	1.9%	1.8%	2.1%	
PJM RTO		849,843	855,958	864,246	871,619	881,358	1.4%
	%	1.4%	0.7%	1.0%	0.9%	1.1%	

Table E-2

**MONTHLY NET ENERGY FORECAST (GWh) FOR EACH
PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION**

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	PJM MID-ATLANTIC
Jan 2009	983	3,245	1,773	2,157	1,464	3,676	1,671	2,947	3,999	4,064	130	106	26,215
Feb 2009	869	2,841	1,572	1,896	1,304	3,250	1,497	2,595	3,533	3,617	114	93	23,181
Mar 2009	885	2,802	1,543	1,963	1,357	3,352	1,580	2,570	3,606	3,821	122	93	23,694
Apr 2009	815	2,486	1,365	1,799	1,215	3,040	1,422	2,353	3,161	3,587	115	80	21,438
May 2009	860	2,570	1,410	1,884	1,248	3,148	1,453	2,477	3,202	3,761	124	79	22,216
Jun 2009	999	3,025	1,631	2,199	1,319	3,544	1,444	2,991	3,317	4,318	146	81	25,014
Jul 2009	1,251	3,502	1,919	2,651	1,460	4,083	1,537	3,404	3,662	5,024	172	91	28,756
Aug 2009	1,225	3,411	1,882	2,538	1,426	3,959	1,535	3,292	3,594	4,856	163	88	27,969
Sep 2009	932	2,761	1,495	1,984	1,233	3,226	1,437	2,712	3,193	3,942	127	77	23,119
Oct 2009	868	2,580	1,418	1,916	1,268	3,160	1,486	2,454	3,247	3,823	123	80	22,423
Nov 2009	851	2,622	1,443	1,889	1,251	3,118	1,463	2,445	3,292	3,708	120	86	22,288
Dec 2009	965	3,083	1,685	2,136	1,421	3,519	1,624	2,823	3,823	4,035	131	102	25,347

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	MID-ATLANTIC
Jan 2010	990	3,265	1,768	2,189	1,465	3,615	1,663	2,962	3,979	4,105	131	105	26,237
Feb 2010	876	2,867	1,570	1,928	1,307	3,203	1,492	2,616	3,523	3,662	115	93	23,252
Mar 2010	900	2,846	1,551	2,010	1,365	3,315	1,578	2,609	3,609	3,888	124	93	23,888
Apr 2010	832	2,526	1,367	1,839	1,221	3,010	1,418	2,374	3,157	3,640	116	79	21,579
May 2010	878	2,613	1,413	1,926	1,257	3,121	1,452	2,501	3,203	3,819	125	78	22,386
Jun 2010	1,018	3,075	1,635	2,247	1,329	3,516	1,445	3,015	3,322	4,385	148	81	25,216
Jul 2010	1,279	3,559	1,923	2,700	1,473	4,069	1,542	3,425	3,669	5,080	174	91	28,984
Aug 2010	1,256	3,486	1,897	2,601	1,456	3,975	1,558	3,334	3,640	4,950	166	89	28,408
Sep 2010	959	2,815	1,503	2,031	1,252	3,230	1,450	2,739	3,218	4,005	129	77	23,408
Oct 2010	900	2,639	1,435	1,968	1,292	3,192	1,508	2,482	3,281	3,896	125	81	22,799
Nov 2010	879	2,680	1,460	1,939	1,286	3,158	1,495	2,472	3,354	3,782	123	87	22,715
Dec 2010	998	3,149	1,708	2,193	1,450	3,558	1,651	2,862	3,867	4,116	133	103	25,788

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	MID-ATLANTIC
Jan 2011	1,028	3,348	1,807	2,253	1,507	3,693	1,704	3,018	4,054	4,209	134	107	26,862
Feb 2011	909	2,932	1,600	1,981	1,338	3,260	1,522	2,653	3,574	3,739	117	94	23,719
Mar 2011	937	2,918	1,582	2,069	1,399	3,378	1,613	2,646	3,667	3,973	127	94	24,403
Apr 2011	890	2,596	1,401	1,902	1,258	3,090	1,457	2,409	3,218	3,735	119	81	22,156
May 2011	941	2,693	1,451	1,997	1,298	3,211	1,497	2,546	3,283	3,924	129	80	23,050
Jun 2011	1,084	3,163	1,676	2,323	1,369	3,610	1,486	3,059	3,395	4,496	151	82	25,894
Jun 2011	1,372	3,645	1,970	2,779	1,509	4,164	1,581	3,466	3,733	5,188	178	93	29,678
Jul 2011	1,352	3,588	1,953	2,699	1,510	4,105	1,615	3,401	3,746	5,104	172	91	29,336
Sep 2011	1,043	2,893	1,545	2,107	1,291	3,328	1,494	2,786	3,291	4,116	132	79	24,105
Oct 2011	986	2,706	1,482	2,047	1,336	3,299	1,561	2,530	3,370	4,012	129	83	23,541
Nov 2011	959	2,747	1,509	2,017	1,330	3,262	1,546	2,524	3,440	3,899	126	89	23,448
Dec 2011	1,076	3,213	1,759	2,271	1,493	3,661	1,702	2,913	3,952	4,230	136	105	26,511

Table E-2

MONTHLY NET ENERGY FORECAST (GWh) FOR EACH
PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO

	AEP	APS	COMED	DAY	DLCO	PJM WESTERN	DOM	PJM RTO
Jan 2009	13,278	4,694	8,978	1,630	1,274	29,854	8,804	64,873
Feb 2009	11,732	4,159	7,984	1,442	1,135	26,452	7,684	57,317
Mar 2009	11,949	4,221	8,324	1,494	1,197	27,185	7,491	58,370
Apr 2009	10,811	3,725	7,680	1,354	1,108	24,678	6,650	52,766
May 2009	11,140	3,785	7,973	1,399	1,165	25,462	6,958	54,636
Jun 2009	11,619	3,955	8,709	1,525	1,256	27,064	8,271	60,349
Jul 2009	12,677	4,357	10,126	1,700	1,409	30,269	9,319	68,344
Aug 2009	12,558	4,307	9,756	1,672	1,375	29,668	9,056	66,693
Sep 2009	11,013	3,773	8,105	1,406	1,166	25,463	7,483	56,065
Oct 2009	11,224	3,851	8,104	1,408	1,157	25,744	6,926	55,093
Nov 2009	11,220	3,926	7,972	1,386	1,131	25,635	7,061	54,984
Dec 2009	12,785	4,556	8,905	1,563	1,242	29,051	8,348	62,746

	AEP	APS	COMED	DAY	DLCO	WESTERN	DOM	PJM RTO
Jan 2010	13,213	4,752	8,987	1,607	1,261	29,820	8,848	64,905
Feb 2010	11,695	4,217	8,008	1,424	1,126	26,470	7,737	57,459
Mar 2010	11,963	4,296	8,385	1,479	1,190	27,313	7,581	58,782
Apr 2010	10,806	3,786	7,764	1,345	1,099	24,800	6,731	53,110
May 2010	11,150	3,850	8,064	1,393	1,158	25,615	7,047	55,048
Jun 2010	11,631	4,022	8,812	1,520	1,249	27,234	8,368	60,818
Jul 2010	12,679	4,418	10,283	1,698	1,404	30,482	9,438	68,904
Aug 2010	12,665	4,401	9,967	1,690	1,381	30,104	9,215	67,727
Sep 2010	11,062	3,841	8,270	1,413	1,167	25,753	7,605	56,766
Oct 2010	11,316	3,921	8,322	1,433	1,161	26,153	7,064	56,016
Nov 2010	11,375	4,024	8,189	1,425	1,139	26,152	7,218	56,085
Dec 2010	12,899	4,648	9,124	1,587	1,247	29,505	8,520	63,813

	AEP	APS	COMED	DAY	DLCO	WESTERN	DOM	PJM RTO
Jan 2011	13,435	4,884	9,306	1,654	1,275	30,554	9,078	66,494
Feb 2011	11,846	4,315	8,267	1,457	1,134	27,019	7,917	58,655
Mar 2011	12,127	4,400	8,675	1,519	1,200	27,921	7,774	60,098
Apr 2011	10,981	3,875	8,121	1,395	1,114	25,486	6,932	54,574
May 2011	11,380	3,957	8,457	1,452	1,176	26,422	7,279	56,751
Jun 2011	11,852	4,124	9,206	1,576	1,266	28,024	8,610	62,528
Jul 2011	12,895	4,510	10,718	1,759	1,424	31,306	9,715	70,699
Aug 2011	12,996	4,533	10,504	1,773	1,412	31,218	9,542	70,096
Sep 2011	11,302	3,939	8,693	1,477	1,188	26,599	7,864	58,568
Oct 2011	11,608	4,028	8,816	1,512	1,188	27,152	7,344	58,037
Nov 2011	11,665	4,136	8,673	1,501	1,165	27,140	7,504	58,092
Dec 2011	13,203	4,767	9,597	1,658	1,272	30,497	8,823	65,831

Table E-3

MONTHLY NET ENERGY FORECAST (GWh)
FOR FE/GPU AND PLGRP

	FE/GPU	PLGRP
Jan 2009	5,292	4,105
Feb 2009	4,697	3,626
Mar 2009	4,900	3,699
Apr 2009	4,436	3,241
May 2009	4,585	3,281
Jun 2009	4,962	3,398
Jul 2009	5,648	3,753
Aug 2009	5,499	3,682
Sep 2009	4,654	3,270
Oct 2009	4,670	3,327
Nov 2009	4,603	3,378
Dec 2009	5,181	3,925

	FE/GPU	PLGRP
Jan 2010	5,317	4,084
Feb 2010	4,727	3,616
Mar 2010	4,953	3,702
Apr 2010	4,478	3,236
May 2010	4,635	3,281
Jun 2010	5,021	3,403
Jul 2010	5,715	3,760
Aug 2010	5,615	3,729
Sep 2010	4,733	3,295
Oct 2010	4,768	3,362
Nov 2010	4,720	3,441
Dec 2010	5,294	3,970

	FE/GPU	PLGRP
Jan 2011	5,464	4,161
Feb 2011	4,841	3,668
Mar 2011	5,081	3,761
Apr 2011	4,617	3,299
May 2011	4,792	3,363
Jun 2011	5,178	3,477
Jul 2011	5,869	3,826
Aug 2011	5,824	3,837
Sep 2011	4,892	3,370
Oct 2011	4,944	3,453
Nov 2011	4,893	3,529
Dec 2011	5,466	4,057

Note: FE/GPU contains JCPL, METED, and PENLC zones; PLGRP contains PL and UGI zones.

TABLE F-1

PJM RTO HISTORICAL PEAKS
(MW)

SUMMER

YEAR	NORMALIZED BASE	NORMALIZED COOLING	NORMALIZED TOTAL	UNRESTRICTED PEAK	PEAK DATE/TIME	
1998	72,950	38,170	111,120	114,996	Tuesday	07/21/1998 17:00
1999	73,990	42,980	116,970	121,655	Tuesday	07/06/1999 17:00
2000	76,300	40,080	116,380	114,178	Wednesday	08/09/2000 17:00
2001	75,990	45,080	121,070	131,116	Thursday	08/09/2001 16:00
2002	77,140	48,120	125,260	130,360	Thursday	08/01/2002 17:00
2003	77,650	46,700	124,350	126,332	Thursday	08/21/2003 17:00
2004			130,645	120,235	Wednesday	06/09/2004 17:00
2005			133,550	134,219	Tuesday	07/26/2005 16:00
2006			134,905	145,951	Wednesday	08/02/2006 17:00
2007			136,095	140,948	Wednesday	08/08/2007 16:00
2008			136,315	130,792	Monday	06/09/2008 17:00

WINTER

YEAR	NORMALIZED BASE	NORMALIZED HEATING	NORMALIZED TOTAL	UNRESTRICTED PEAK	PEAK DATE/TIME	
97/98				88,970	Wednesday	01/14/1998 19:00
98/99				99,982	Tuesday	01/05/1999 19:00
99/00				102,359	Thursday	01/27/2000 20:00
00/01				101,717	Wednesday	12/20/2000 19:00
01/02				97,294	Thursday	01/03/2002 19:00
02/03				112,755	Thursday	01/23/2003 19:00
03/04			108,110	106,760	Monday	01/26/2004 19:00
04/05			110,250	114,061	Monday	12/20/2004 19:00
05/06			111,745	110,415	Wednesday	12/14/2005 19:00
06/07			112,455	118,800	Monday	02/05/2007 20:00
07/08			113,185	111,724	Thursday	01/03/2008 19:00

Notes: Normalized values for 1998 - 2003 are calculated by PJM staff using the bottom-up coincident peak weather-normalization methodology.
Normalized values for 2004 - 2008 are calculated by PJM staff using a methodology consistent with the PJM Load Forecast Model.
All times are shown in hour ending Eastern Prevailing Time.

TABLE F-2

PJM RTO HISTORICAL NET ENERGY
(GWH)

YEAR	ENERGY	GROWTH RATE
1998	620,061	0.8%
1999	636,404	2.6%
2000	651,190	2.3%
2001	651,319	0.0%
2002	673,526	3.4%
2003	674,471	0.1%
2004	689,008	2.2%
2005	682,441	-1.0%
2006	694,989	1.8%
2007	724,541	4.3%

Note: All historic net energy values reflect the membership of the PJM RTO as of December 31, 2008.

Table G-1

ANNUALIZED AVERAGE GROWTH OF GROSS METROPOLITAN PRODUCT
FOR EACH PJM ZONE AND RTO

	5-Year (2009-14)	10-Year (2009-19)	15-Year (2009-24)
AE	4.3%	2.9%	2.3%
BGE	3.1%	3.0%	2.8%
DPL	3.7%	3.1%	2.9%
JCPL	3.2%	2.4%	2.0%
METED	2.2%	1.6%	1.3%
PECO	1.8%	1.4%	1.2%
PENLC	1.8%	1.8%	1.6%
PEPCO	3.1%	2.7%	2.5%
PL	1.9%	1.4%	1.1%
PS	3.3%	2.5%	2.1%
RECO	3.3%	2.6%	2.2%
UGI	1.5%	1.0%	0.7%
AEP	2.5%	1.7%	1.4%
APS	2.7%	2.1%	1.9%
COMED	3.3%	2.4%	1.9%
DAY	2.2%	1.4%	1.0%
DLCO	2.0%	1.9%	1.7%
DOM	2.9%	2.5%	2.4%
PJM RTO	2.9%	2.3%	1.9%

Source: Moody's Economy.com, December, 2008

Note: Values presented are annualized compound average growth rates.

Exhibit RMF-5

PJM Interconnection

Summer 2009 Weather Normalized Coincident Peaks (MW)

Zone	Peak
AE	2,550
AEP	22,540
APS	8,150
BGE	7,000
COMED	21,300
DAYTON	3,150
DLCo	2,760
DOM	18,290
DPL	3,800
JCPL	6,060
METED	2,770
PECO	8,260
PENLC	2,680
PEPCO	6,690
PL	6,850
PS	10,340
RECO	410
UGI	180
PJM RTO	133,780

Summer 2009 Coincident Peaks (5CP)

Note: All times are listed in Hour Ending EPT

PJM RTO

Day	Date	Hour	MW
Monday	8/10/2009	17:00	126,944
Tuesday	8/18/2009	16:00	122,369
Monday	8/17/2009	17:00	121,933
Tuesday	8/11/2009	17:00	120,708
Thursday	8/20/2009	17:00	120,112

CERTIFICATE OF SERVICE

I, Emily Greenlee, hereby certify, under penalty of perjury, that a true and correct copy of the foregoing Direct Testimony of Bob Fagan on Behalf of the Sierra Club was served to the following by electronic mail or U.S. mail, first class, postage prepaid on this 23rd day of October, 2009:

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