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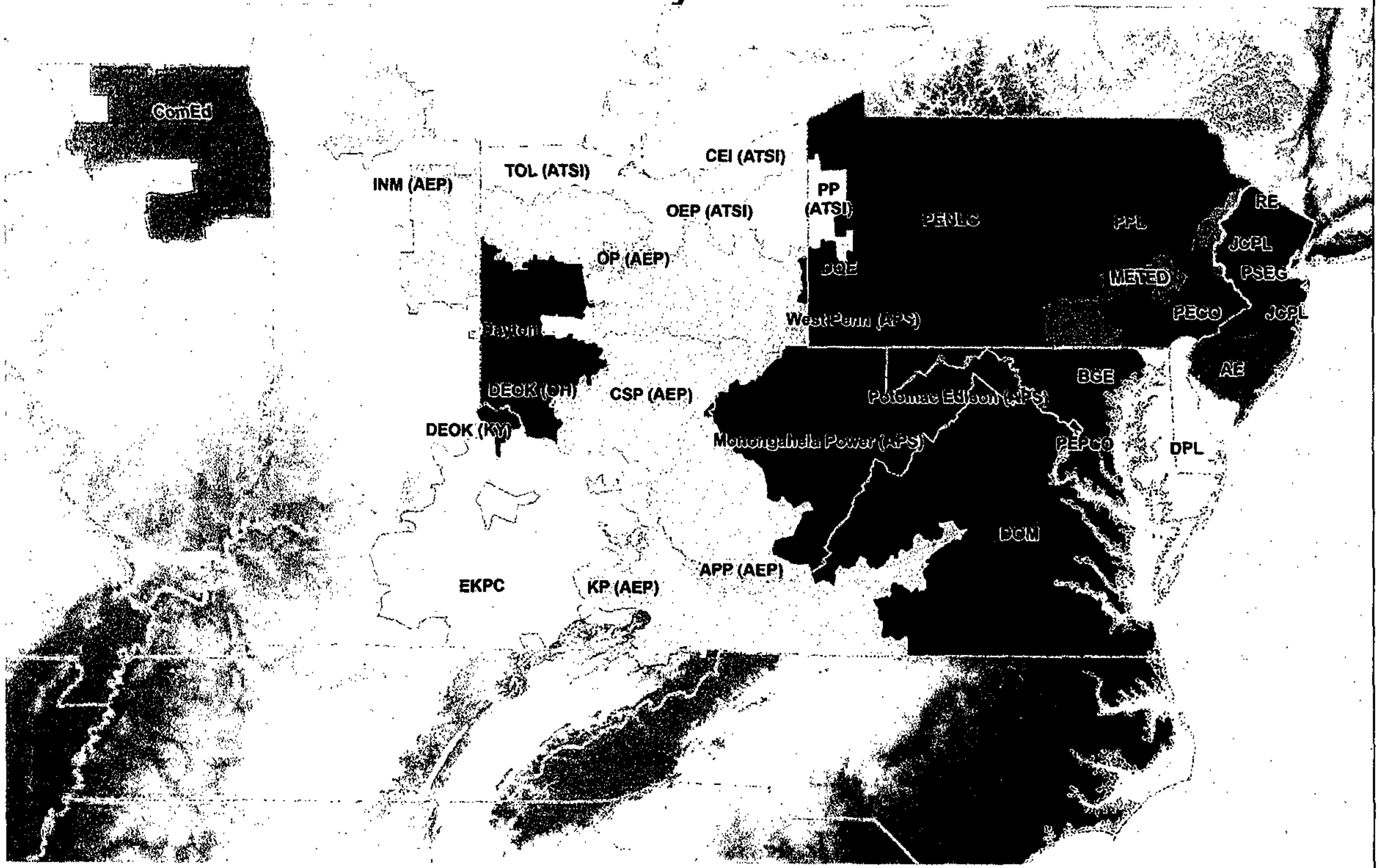
PJM Load Forecast Report
January 2016



Prepared by PJM Resource Adequacy Planning Department

EXHIBIT
COMPANIES 171

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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)
ATSI	American Transmission Systems, Inc. zone (incorporated 6/1/2011)
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
CEI	Cleveland Electric Illuminating, sub-zone of ATSI
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)
DEOK	Duke Energy Ohio/Kentucky zone (incorporated 1/1/2012)
DLCO	Duquesne Lighting Company zone (incorporated 1/1/2005)
DOM	Dominion Virginia Power zone (incorporated 5/1/2005)
DPL	Delmarva Power & Light zone (part of Pepco Holdings, Inc)
EKPC	East Kentucky Power Cooperative (incorporated 6/1/2013)
FE-East	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
NERC	North American Electric Reliability Corporation
Net Energy	Net Energy for Load, measured as net generation of main generating units plus energy receipts minus energy deliveries
OEP	Ohio Edison, sub-zone of ATSI
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
PP	Pennsylvania Power, sub-zone of ATSI
PS	Public Service Electric & Gas zone
RECO	Rockland Electric (East) zone (incorporated 3/1/2002)
TOL	Toledo Edison, sub-zone of ATSI
UGI	UGI Utilities, sub-zone of PLGroup
Unrestricted Peak	Peak load prior to any reduction for load management, accelerated energy efficiency or voltage reduction.
WP	West Penn Power, sub-zone of APS
Zone	Areas within the PJM Control Area, as defined in the PJM Reliability Assurance Agreement

2016 PJM LOAD FORECAST REPORT

EXECUTIVE SUMMARY

- This report presents an independent load forecast prepared by PJM staff.
- The report includes long-term forecasts of peak loads, net energy, load management and distributed solar generation for each PJM zone, region, locational deliverability area, and the total RTO.
- All load models were estimated with historical data from January 1998 through August 2015. The models were simulated with weather data from years 1994 through 2014, generating 273 scenarios. The economic forecast used was Moody's Analytics' October 2015 release. Equipment indexes reflect the 2015 update of Itron's end-use data, which is consistent with the Energy Information Administration's 2015 Annual Energy Outlook.
- Table B-7 has been revised to reflect the transition of Demand Resource options available under the Capacity Performance rules of the Reliability Pricing Model.
- Table B-8 has been modified; it now represents the amount of distributed solar generation subtracted from each forecast year. These values reflect the impact of historical distributed solar generation at peak as well as the forecasted amount of solar additions at peak in each forecast year. **Distributed solar generation forecast values have already been subtracted from all forecast tables in the report.**
- With the adoption of a new load forecast model, PJM has reverted to publishing only one set of E-Tables (net energy).
- Since the 2015 report, PJM has significantly revised its load forecast model. The treatment of weather has been restructured to provide more variable load response to weather across a wide range of conditions. Three variables (cooling, heating, and other) were added to account for trends in equipment/appliance saturation and efficiency, and distributed solar generation is now reflected in the historical load data used to estimate the models, with a separately-derived solar forecast used to adjust load forecasts. Detailed information on the development of the distributed solar generation forecast can be found at: http://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process.aspx.
- The economic regions used for each zone have been revised to be consistent with the revised definitions of metropolitan areas of the U.S. Office of Management and Budget. An exception is DOM zone, for which economic data for the Commonwealth of Virginia is now used. Weather station mixtures have been revised for AEP, EKPC, and PL zones.

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

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

- The PJM RTO weather-normalized summer peak for 2015 was 150,295 MW (using the new normalization method). The projection for the 2016 PJM RTO summer peak is 152,131 MW, an increase of 1,836 MW, or 1.2%, from the 2015 normalized peak.

- Summer peak load growth for the PJM RTO is projected to average 0.6% per year over the next 10 years, and 0.6% over the next 15 years. The PJM RTO summer peak is forecasted to be 161,891 MW in 2026, a 10-year increase of 9,760 MW, and reaches 167,469 MW in 2031, a 15-year increase of 15,338 MW. Annualized 10-year growth rates for individual zones range from -0.1% to 1.2%.

- Winter peak load growth for PJM RTO is projected to average 0.8% per year over the next 10-year period, and 0.8% over the next 15-years. The PJM RTO winter peak load in 2025/26 is forecasted to be 140,912 MW, a 10-year increase of 10,669 MW, and reaches 146,225 MW in 2030/31, a 15-year increase of 15,982 MW. Annualized 10-year growth rates for individual zones range from 0% to 1.6%.

- Compared to the 2015 Load Report, the 2016 PJM RTO summer peak forecast shows the following changes for three years of interest:
    - The next delivery year – 2016 -5,781 MW (-3.7%)
    - The next RPM auction year – 2019 -5,660 MW (-3.5%)
    - The next RTEP study year – 2021 -8,406 MW (-5.1%)

NOTE:

Unless noted otherwise, all peak and energy values are non-coincident, unrestricted peaks, which represent the peak load or net energy after reductions for distributed solar generation and prior to reductions for load management impacts.

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

Summary Table

SUMMER PEAK LOAD (MW) AND GROWTH RATES FOR PJM RTO AND SELECTED GEOGRAPHIC REGIONS

	METERED 2015	UNRESTRICTED 2015	NORMAL 2015		THIS YEAR 2016	RPM YEAR 2019	RTEP YEAR 2021
PJM RTO	143,446	143,496	150,295		152,131	156,958	157,358
				Growth Rate	1.2%		
Demand Resources					-8,777	-9,035	-3,424
PJM RTO - Restricted					143,354	147,923	153,934
PJM MID-ATLANTIC	54,889	54,889	56,495		57,174	58,464	58,310
				Growth Rate	1.2%		
Demand Resources					-3,556	-3,627	-1,347
MID-ATL - Restricted					53,618	54,837	56,963
EASTERN MID-ATLANTIC	30,240	30,240	31,095		31,278	31,924	31,709
				Growth Rate	0.6%		
Demand Resources					-1,289	-1,315	-494
EMAAC - Restricted					29,989	30,609	31,215
SOUTHERN MID-ATLANTIC	12,419	12,419	12,810		13,393	13,624	13,652
				Growth Rate	4.6%		
Demand Resources					-1,130	-1,149	-425
SWMAAC - Restricted					12,263	12,475	13,227

Note:
Normal 2015 and all forecast values are non-coincident as estimated by PJM staff.
Except as noted, all values reflect the membership of the PJM RTO as of June 1, 2015.

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December 2015

Adam Ozimek, 610-235-5127

Summary of the December 2015 U.S. macro forecast

The U.S. economy performed well in 2015, and 2016 should be even better. The economy is on track to return to full employment by midyear. It will have been almost a decade since the economy was last operating at full tilt.
Full employment is consistent with a 5% unemployment rate, which has already been achieved, and a 9% underemployment rate. Underemployment includes the unemployed, part-timers who want more hours, and potential workers that have stepped out of the workforce and thus are not counted as unemployed but say they want a job. This is the so-called U-6 unemployment rate, which currently stands at 9.8%. On a full-time equivalent basis—translating the part-timers into full-timers—it is about 9.6%.

At the current pace of job growth of more than 200,000 per month, if sustained, the economy will be back to full employment by next summer. To be even more precise, given that the working-age population is growing by only 100,000 per month, the underemployment or U-6 unemployment rate should stand at 9% by August. There is clearly much uncertainty around this estimate, but there is little doubt that full employment is approaching fast.

Job machine

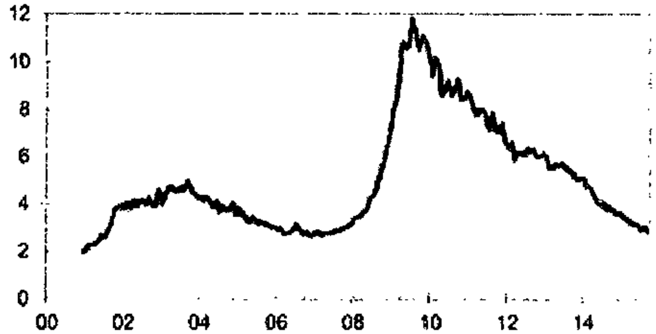
Businesses are adding jobs at a consistent and prodigious rate. Payrolls will expand by almost 3 million in 2015, about the same as the year before and the year before that. The last time job growth was as consistently strong was during the technology boom of the late 1990s.

The oil price collapse and resulting rationalization in the energy industry, and the stronger U.S. dollar and weakening in trade-sensitive manufacturing have slowed job growth a notch in recent months. But these constraints should fade by the spring. Moreover, job creation in the rest of the economy shows no signs of slowing.

Most encouraging is that job openings are about as plentiful as they have ever been. There are now less than three underemployed for every open job position.

Full Employment Is Approaching Fast

U-6 underemployed per open job position



Sources: BLS, Moody's Analytics

For context, at the worst of the recession, there was closer to 11 underemployed for each open position. Openings are widespread across most industries, but particularly in healthcare and professional services—two industries adding aggressively to their roles. Layoffs also remain extraordinarily low, with nearly record low numbers filing for unemployment insurance.

Wage resurgence

The tightening job market is evident from the recent firming in wage growth. According to the Bureau of Labor Statistics, average hourly earnings and wages as measured by the employment cost index have picked up meaningfully over the past year. After abstracting from the short-term ups and downs in these measures, wage growth is up nearly half a percentage point over the past year, well over the near 2% year-over-year growth that had prevailed since the recession.

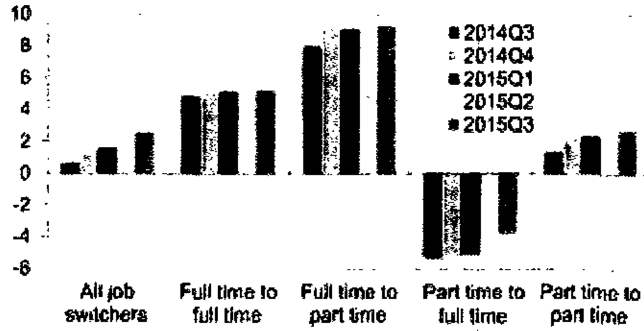
Wage growth is even stronger than indicated by the BLS wage data. The BLS calculates wages based on reports from establishments that average pay across all their employees. Measured wage growth is being depressed as many lower-paid millennials are coming into the workforce, while higher-paid boomers are leaving it. The tighter labor market also means that those now finding jobs are likely less productive and thus lower-paid.

The importance of these worker-mix effects is evident from wage data constructed by Moody's Analytics based on payroll records maintained by human resource company ADP. The ADP data are derived by tracking the wages of individuals and are thus *not* impacted by the changing mix of workers in establishments. According to ADP, year-over-year wage growth for individuals is just more than 4%. Like the BLS data, ADP measured wage growth has accelerated by about half a percentage point over the past year.

A positive near-term leading indicator of future wage growth in the ADP data is the pickup in wages paid to workers switching jobs. Across all switchers, pay increases have risen substantially over the past year.

Job Switchers Enjoy Bigger Wage Increases

Wage increase, 4-qtr MA, %



Sources: ADP, Moody's Analytics

Part-timers switching to either another part-time job or a full-time job enjoyed the biggest improvement. Switcher wages have accelerated across all but the energy industry and are up most in the construction trades and in healthcare. All age groups are enjoying increased switcher wages, but those in their prime working years of 35 to 54 have seen the largest acceleration. Switcher wages are up in all parts of the country, but most in the South and Midwest.

Wage risks

Wage growth is expected to accelerate substantially as the economy attains full employment. It may take a while, but wages are ultimately expected to reach a 3.5% growth rate. This is equal to the sum of inflation, which is expected to be near the Federal Reserve's 2% target, and 1.5% trend labor productivity growth. At this pace of growth, labor's share of national income will stabilize; labor's share has been shrinking more or less since the early 1980s.

There are both downside and upside risks to this outlook. On the downside is persistently weak productivity growth, which has been well below 1% per annum in recent years. Productivity is expected to pick up as businesses refocus on it. With labor costs so low since the recession, businesses have felt little pressure to invest in labor-saving technologies. This should change as businesses realize that their labor costs are rising with the tightening job market, but this is still a forecast.

On the upside is the likelihood that the job market will overshoot full employment. By the end of 2016, it will be clear that the economy's biggest problem is not unemployment, but a lack of qualified labor. Businesses in a rising number of industries will be in bidding wars for workers. According to

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homebuilders, this is already an issue in the construction trades, and manufacturers are also complaining they cannot find the highly skilled workers they need.

Rate normalization

Firming wage growth is the signal that the Federal Reserve has needed to begin normalizing interest rates. Policymakers indicate that the coming rate hikes will be gradual, with the funds rate ending 2016 at just more than 1%. This is a reasonable forecast, given that inflation remains well below the Fed's target, and the Fed's desire to err on the side of too strong an economy rather than a struggling one. The Fed desperately wants to avoid backtracking on the rate hikes or, even worse, having to resume quantitative easing or adopting other nontraditional policies.

Policymakers also rightly want to see what impact the rate hikes will have on broader financial market conditions. The stock market appears vulnerable, given its currently high valuation; an even stronger U.S. dollar seems likely; and credit spreads have the potential to significantly gap out, particularly for below-investment-grade corporate bonds. The seeming lack of transactional liquidity in markets could also exacerbate the volatility in all markets.

Financial pressures on already-fragile emerging markets could also intensify. Most vulnerable are countries that rely heavily on capital inflows and whose nonfinancial businesses have issued debt in dollars.

These include Turkey, South Africa, and a number of countries in Latin America and Southeast Asia. Growth in the EMs slowed sharply this past year, and the best that can be expected in the coming year is that they stabilize.

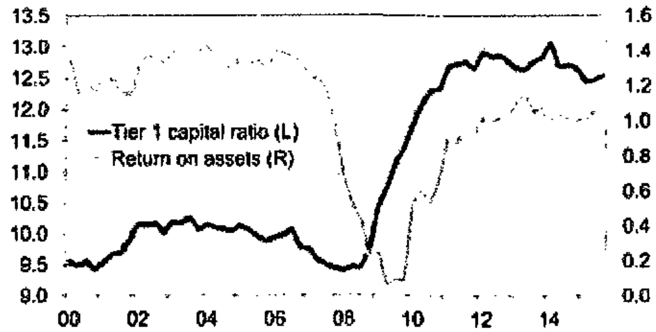
R* equilibrium

Just where the rate hikes end depends on the equilibrium funds rate, or R*—that funds rate consistent with an economy operating at its potential and inflation at the Fed's 2% target. There is a general consensus that R* has fallen since the Great Recession, but there is little consensus regarding by how much. The Fed's long-run forecast of the funds rate would suggest that the equilibrium funds rate is approximately 3.5%. This is equal to the sum of the Fed's 2% inflation target, the economy's potential growth rate, and the impact of various economic "headwinds."

Although not well-defined, the most significant headwind is the higher required capitalization and liquidity of the banking system post-crisis.

Bank Capitalization Is Higher, Profitability Lower

Commercial banks



Sources: FDIC, Moody's Analytics

If regulators require that banks must hold more capital and be more liquid, then the banks' return on equity and assets will be lower. Thus for the system to extend the same amount of credit to the economy at the same lending rates, the system's cost of funds needs to fall by a like amount as its returns. That is, banks' lending margins—loan rates less cost of funds—must be maintained. This can be achieved if the Fed adopts a lower R*, and thus lower banks' cost of funds. *Like the Fed, we also estimate R* to be 3.5%, equal to 2% inflation, plus 2.2%* potential real GDP growth, less 0.7% to account for the economic headwinds. The actual federal funds rate is expected to reach our 3.5% R* by spring 2018.

Rate risks

The Fed's path to R* is rife with risk. The equilibrium funds rate could be much lower than we are estimating, either because potential growth is lower or the headwinds are blowing harder. Financial markets seemingly believe this, as the futures market for fed funds puts the funds rate at closer to 2% by early 2018. However, there is also the risk that the economy will overshoot full employment, generating significant wage and prices pressures and forcing the Fed to ultimately play catch-up in raising rates. Indeed, the more gradual the rate hikes are in 2016, *the more likely the Fed will have to increase rates more aggressively in 2017-2018* to forestall an overheating economy.

Certainly a lot could go wrong between now and 2018. But that should be a worry for another day. We should enjoy 2016 and a full-employment economy.

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Risks to the U.S. outlook

If the Fed jumps the gun and is forced to reverse course, quantitative easing would be restarted and negative interest rates would be possible. There are other options. Former Fed Chairman Ben Bernanke recounts in his new book some of the policies the Fed considered but did not implement during the Great Recession. They include negative interest rates, funding for lending, raising the inflation target, and pegging interest rates on securities with maturities of two years or less. The latter would be a commitment to keep rates low for at least two years, but the balance sheet would increase substantially. Nominal GDP targeting would be a radical option. The options Bernanke discussed could be the playbook if the Fed has to quickly reverse course.

Softer global demand, particularly in China and Europe, will hurt domestic exports and could cause GDP growth to fall short of expectations should the situation deteriorate further. The slowdown in China's economy is weighing heavily on the emerging economies in Asia and Latin America; this in turn has led to steep corrections in international equity markets. Further, Chinese policymakers could fumble in their efforts to try and stimulate growth, leading to further selloffs in China's equity markets. Slower global growth will hurt Midwest factories and coastal shipping hubs and is already subtracting from U.S. output growth. The main risk is that weakness will persist for longer than anticipated.

The weakness in global demand for U.S. exports will be aggravated by a stronger U.S. dollar. Trade data have been soft in recent months as the rising greenback has squeezed the market share of domestic firms. The impact has been most apparent in low-value-added industries that already struggle with fierce international competition. The widening divergence between U.S. monetary policy and monetary policy in Europe and Asia could cause the greenback to strengthen more than expected. The baseline forecast already assumes that the dollar will appreciate relative to the euro and the yen, as central bankers in these regions have initiated large-scale quantitative easing programs that will weaken their currencies. If foreign policymakers adopt even more expansionary policies, or if U.S. rates rise faster than expected, the dollar will push beyond the baseline forecast, further widening the trade deficit and causing GDP to fall below expectations.

Global tensions pose an indirect threat to the U.S. economy through the channels of global trade, consumer sentiment and financial markets. The conflict between Ukraine and Russia has led to a standoff between Russia and the West. With no resolution in sight, sanctions will likely prevail through next year and could push Russia deeper into recession. The consequences of the sanctions are disruptive for the euro zone economy, especially Germany, and could derail the euro zone's fragile recovery.

Conflicts in Iraq and Syria threaten to further destabilize the region. While the war against the Islamic State has been confined to Iraq and Syria, it could spread to other Middle Eastern countries, risking increased intervention by the West. The worst-case scenario involves escalated tensions in the region that could cause not only a spike in oil prices but also greater turmoil in global financial markets, leading to a drop in trade and slower global growth. Furthermore, instability in the region has triggered an exodus of refugees from Syria. The wave of migrants puts the EU's immigration system under tremendous stress as EU members struggle to establish a system to relocate refugees from overburdened countries.

Output growth will suffer if the U.S. dollar strengthens faster than expected. The currency will appreciate relative to the euro and the yen as monetary actions in the U.S., Europe and Japan are expected to diverge further and spreads between policy rates widen. A stronger dollar will be a net negative for the U.S. Exports will slow further and imports will rise rapidly, trends already evident in the U.S. trade deficit widening to $43.9 billion in October.

Further, the relationship is nonlinear, with the dollar subtracting an increasingly larger share of gross domestic output as it gains. Additionally, if foreign policymakers initiate even more expansive policies, or if U.S. rates rise faster than expected, the dollar will rise above the baseline forecast. In this event, U.S. exporters will be hit hard, imports will rise faster, and GDP will fall below expectations.

Summary of the forecast for PJM service territories

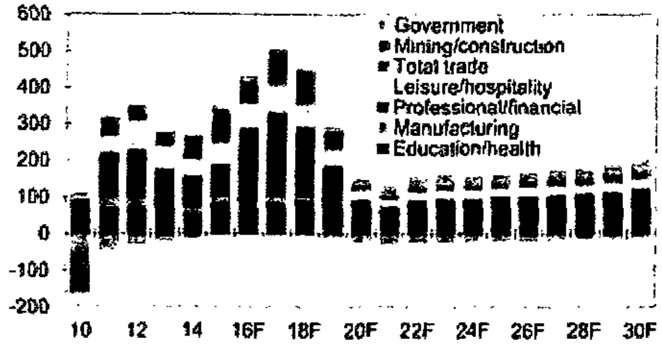
The PJM service territory covers all or parts of 13 states and the District of Columbia, accounting for more than 52 million people, or about a sixth of the U.S. population. The regional economies of the service territory include metro areas in the Midwest, South and Northeast and run the gamut from highly diversified, large economies such as Chicago, to small economies that depend heavily on one industry, such as Elkhart-Goshen IN.

Overall, education/healthcare remains the dominant industry in the service territory. Job growth for the industry has consistently outpaced the overall service territory economy and the gap has widened over the past year. This is attributable to the fading adjustment costs from the Affordable Care Act. Over the longer term, increasing demand from the aging population within the service territory and out will support job gains because of its greater utilization of healthcare services. Healthcare is an export industry to some economies in the service territory.

Consistent with the historical trend, education- and healthcare-related services will provide a significant share of new jobs in the forecast period.

Professional/Financial a Source of Job Gains

Employment, difference, ths



Sources: BLS, Moody's Analytics

On average, the concentration of manufacturing in the service territory is roughly in line with the national average. However, approximately 60% of the metro areas, mainly smaller old-line manufacturing localities in the Northeast and Midwest, rely more heavily on industrial production for growth. The highest concentration of manufacturing is in Elkhart-Goshen IN, where nearly half of all jobs are in manufacturing. In contrast, the lowest concentration is in California-Lexington Park MD, where less than 1% of employment is in manufacturing.

The natural resources and mining industry represents a small portion of the service territory's economy, but has been a source of weakness recently. Low energy prices, a glut of natural gas, and heightened regulatory burdens on coal producers have left the industry shedding employment in 2015. The losses have been widespread in the service territory, with significant declines in Pennsylvania, Ohio, Virginia and West Virginia. Weakness is visible outside of manufacturing as the appreciation in the U.S. dollar, weakness in global demand, and a turn in the inventory cycle have weighed on output. Some of these weights will prove more persistent than others. The dollar will likely appreciate further as the Fed will be the first major central bank to begin tightening monetary policy while many others continue to ease.

While the public sector has a slightly smaller presence in the service territory than it does nationally, there is a greater concentration of federal government employment. This is largely due to the presence of the Washington-Arlington-Alexandria metro division, which contains the nation's capital and is home to one out of 10 federal government employees. With federal budget deficits under 3% and the deficit forecast over the next 10 years improving, the political pressure for austerity has declined. However, poor state fiscal positions in Illinois and Pennsylvania present a risk to the forecast for the service territory.

Recent Performance

The service territory economy continues to improve. While the estimate of GDP growth from the third quarter of 2014 to the third quarter of 2015 is lower than expected, it is due to an upward revision to GDP in 2014.[1] Similarly, total employment growth of only 1.3% in the year to the third quarter of 2015 falls short of the forecast of 1.7%, however this is again due to a stronger than expected end to 2014. Total employment is essentially equal to the 19.6 million forecast.

Healthcare/education has tracked the forecast, as job growth has accelerated. The acceleration is due to fading adjustment costs from the Affordable Care Act, which had weighed on hospital profitability and employment in particular. In addition, declining uninsured rates due to the Affordable Care Act and state Medicaid expansions are increasing the demand for healthcare services as well.

The tightening in the job market and increased churn have boosted income as jobs are more plentiful and employers must increasingly raise wages to hire and retain workers. Real income growth to the second quarter, the most recent available data, has outpaced the forecast by almost a full percentage point. The added income has boosted consumer spending, which has benefited leisure/hospitality. Employment in leisure/hospitality is rising nearly twice as fast as overall employment, and is now well above last year's forecast.

Manufacturing employment is up slightly from a year ago as it outperformed in 2014 before falling short of expectations this year. Manufacturing is an important driver, particularly in many of the territory's Midwest metal-producing and auto-related metro areas. A stronger dollar has held job growth back recently by eroding international competitiveness of manufacturing exports. However, manufacturing has benefited from robust growth in auto demand and transportation equipment manufacturing, which significantly outpaced overall factory production over the last year. Toledo OH, for example, experienced fast growth because of its auto assemblers and parts manufacturers. U.S. vehicle sales are robust, exceeding 18 million annualized units in each of the past three months.

Finance has been another source of job gains, outperforming the forecast for most of the last year. One factor is that headwinds from a recent spate of bank mergers and acquisitions have eased. In recent years, mergers and acquisitions have weighed on growth as banks have sought efficiencies and economies of scale. BB&T Corp. alone has spent $4.3 billion on acquisitions in Pennsylvania, making it the fourth largest bank in the state. These headwinds appear to have weakened somewhat in 2015, however finance in the service territory is still lagging that of

[1] The metro definitions used were changed by the U.S. Office of Management and Budget, making a comparison of the 2014 to 2015 forecast impossible for the full service territory. When direct comparisons of the 2014 and 2015 forecast for the service territory are discussed, they will refer to only a subset of the metro areas and metro divisions for which this comparison is possible. These areas cover 71% of the total service territory employment.

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the U.S. overall, which suggests they remain a factor. Also, financial market conditions tightened in the second half of this year amid initial concerns about the Fed's exit strategy and the deterioration in China's economy.

While some metro areas grew fast in the service territory, others suffered job losses this year. The biggest losses were in Atlantic City NJ, where the casino industry has struggled under stiff regional competition. Total employment in the Atlantic City metro area is among the lowest since the early 1990s. Lebanon PA was also one of the worst-performing metro areas, in part because of the closing of a large distribution center.

While the economy is improving overall, the service territory is adding jobs more slowly than the nation partly because low growth in government employment has disproportionately affected the service territory. Federal government accounts for 3% of total employment, compared with 2% in the rest of the U.S. The concentration is noticeably higher in the District of Columbia, Maryland, and Virginia. Moreover, federal workers earn more in the Mid-Atlantic than elsewhere in the country. Therefore, federal layoffs do more damage to incomes.

Local government is adding jobs again thanks to steady improvement in the housing market that has lifted property taxes. However, it remains a source of weakness in some areas because of state and local fiscal problems, in particular Illinois and Pennsylvania. Increasing pension costs are weighing on some areas, which has led local government employment to fall in Philadelphia, Allentown-Bethlehem and Lebanon PA.

Pennsylvania and Ohio are steadily adding jobs, which account for a substantial portion of PJM's customers. Ohio and Pennsylvania metro areas make up 36% of the territory's payroll employment.

Ohio's recovery remains on track, driven by robust gains in high-paying professional and financial services as well as healthcare. High-value-added white-collar services including consulting and computer systems design are booming in Cincinnati and Columbus. Auto manufacturing is also powering forward thanks to major capital investments and rising national vehicle demand even though broad-based growth in the factory sector has eased because of protracted weakness in steel production.

Pennsylvania's economy is improving, but poor demographics and state fiscal problems are limiting job growth, which ranks in the bottom quintile of U.S. states.

Income growth across the region is helping tourism flourish and generating strong job gains in arts/entertainment/recreation, especially in Philadelphia, Pittsburgh and Allentown-Bethlehem.

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Near-term outlook and changes to the forecast

The October 2015 regional baseline forecast was generated in the context of the U.S. macro forecast. Changes to the near-term outlook for the PJM service territory are similar to those in the U.S. macro forecast. The recent performance was slightly weaker than expected. As a result, the forecast has been lowered for the next few quarters, but raised starting in the end of 2016.

Manufacturing is an area that fell short of expectations in 2015 because of the stronger dollar, low energy prices, weakness in global demand, and a turn in the inventory cycle in the second half of the year. However, following a wider U.S. trend, the near-term outlook for manufacturing job growth has been lifted, and employment is expected to expand through the end of 2017. Manufacturing employment grew an estimated 1.3% since the third quarter of 2014, falling short of expectations of a 1.7% increase. As the U.S. economy heats up over the next two years, this will spur more domestic demand for manufacturing and drive job growth.

The single-family housing market has improved somewhat, but the robust catch-up in single-family permitting that was expected has not materialized. Long-lasting scars from the Great Recession and slack in the job market have left households hesitant to make the investment in single-family housing. This has spurred demand for multifamily housing, but not enough to prevent overall permitting from falling short of the forecast.

Despite the disappointing housing market, construction employment in the service territory has tracked the forecast as commercial and infrastructure projects have helped fill the gap. Both Pennsylvania and Illinois have passed significant infrastructure spending bills in recent years. In Pennsylvania, more than $1.7 billion is being spent on turnpike projects alone in 2015.

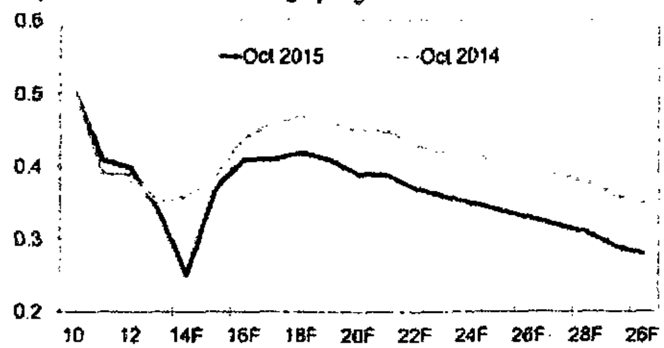
Overall, the return of the service territory economy to full employment will be more gradual than expected, and as a result above-trend job growth will last longer than previously expected. This short-term outlook mirrors the U.S. macro forecast. Over the past year, the service sector has fallen short of expectations. Service growth will improve into 2016 and deliver a less rapid but more prolonged recovery period before settling into longer-term growth rates.

Long-term outlook

The October 2015 forecast for long-term GDP growth in metro areas in the PJM service territory has been slightly upgraded from 2014. Over the next few years, faster household formation than previously expected will boost economic growth.

Population Projections Lowered Slightly...

Population forecast, % change yr ago

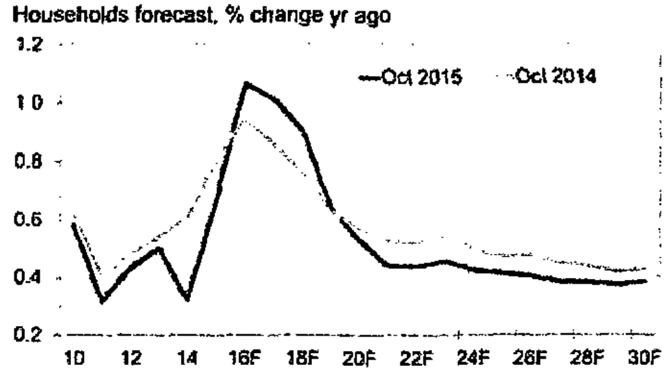


Sources: Census Bureau, Moody's Analytics

For the metro areas in the service territory that are comparable to the previous forecast, the October 2015 forecast is for population to expand 5.7% between 2015 and 2030, down from 6.6% in the October 2014 forecast. As a result the forecast population will be 435,000 lower by 2030 than previously expected. For the full service territory, including newly added and changed metro areas, population growth over this period will be 7%.

...But Household Formation Will Rise Soon...

Households forecast, % change yr ago

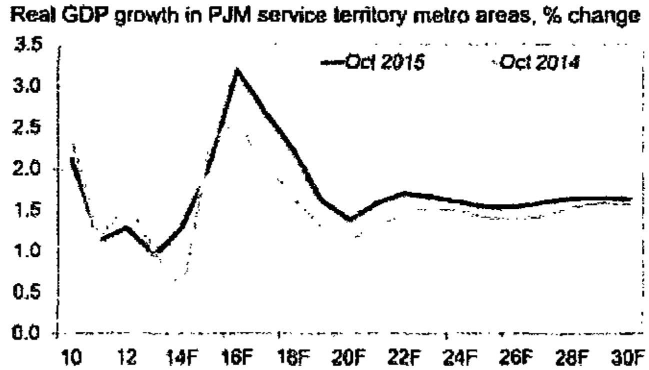


Sources: Census Bureau, Moody's Analytics

Weaker population growth translates to fewer households in the long run. However, in the near term the household formation rate is expected to increase thanks to an improving economy. Scars from the Great Recession have kept the household formation rate below equilibrium. As the labor market tightens and income growth accelerates over the next two years, household formation will pick up and make up for lost ground. Once catch-up household formation has been exhausted, the formation rate will decline to levels consistent with the service territory's slowly growing population.

...Boosting Output Growth in the Short Run

Real GDP growth in PJM service territory metro areas, % change



Sources: BEA, Moody's Analytics

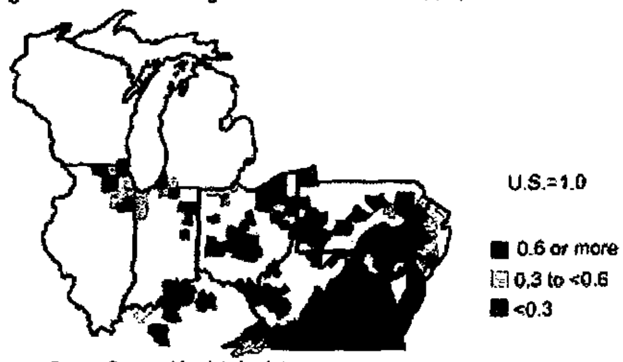
Overall, the long-term GDP forecast has not been altered substantially. The PJM service territory will underperform the U.S., with average annual real GDP growth of 1.9% from 2016 to 2030, compared with the U.S. average of 2.1%. Relative to last year, GDP growth in the parts of the service territory that are comparable to last year are expected to grow 0.2 percentage point faster.

The southernmost metro areas, including the southern parts of Pennsylvania, are expected to be among the fastest-growing in the PJM service territory. The biggest comparative advantage for these areas is their favorable demographic trends, which will help boost overall final demand. While the long-term forecast is weaker, household formation will rebound in 2016 and will drive growth in consumer-based services, including education/healthcare and leisure/hospitality.

Suburban areas are outperforming the cities they neighbor in several cases, thanks to higher levels of education and the regulatory and policy problems that big cities face. For example, the Elgin metro division is expected to outpace the Chicago metro division in terms of population and GDP growth, and Montgomery-Bucks-Chester will do the same for Philadelphia. Washington DC will outperform the service territory thanks to a highly educated labor force, productivity growth, and positive demographic trends.

Stronger Demographics Benefit the South

Avg annual household growth from 2015 to 2030, %

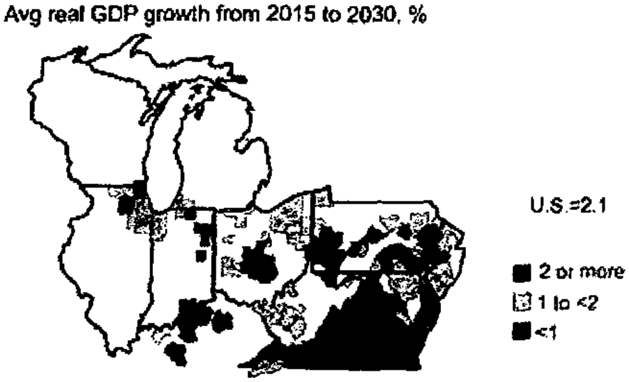


Sources: Census Bureau, Moody's Analytics

Metro areas in Ohio, West Virginia, and western and northern Pennsylvania will expand more slowly. Expansion in those states will be more restrained as the region transitions away from manufacturing toward more service-oriented economies. With lower-value-added services accounting for a larger part of the regional economies, income gains are expected to be more restrained. Weaker demographics will also undermine long-term growth, as workers and their families are expected to seek opportunities in stronger labor markets outside of the slow-growth metro areas in the Midwest and Northeast.

Service Territory Will Underperform the U.S.

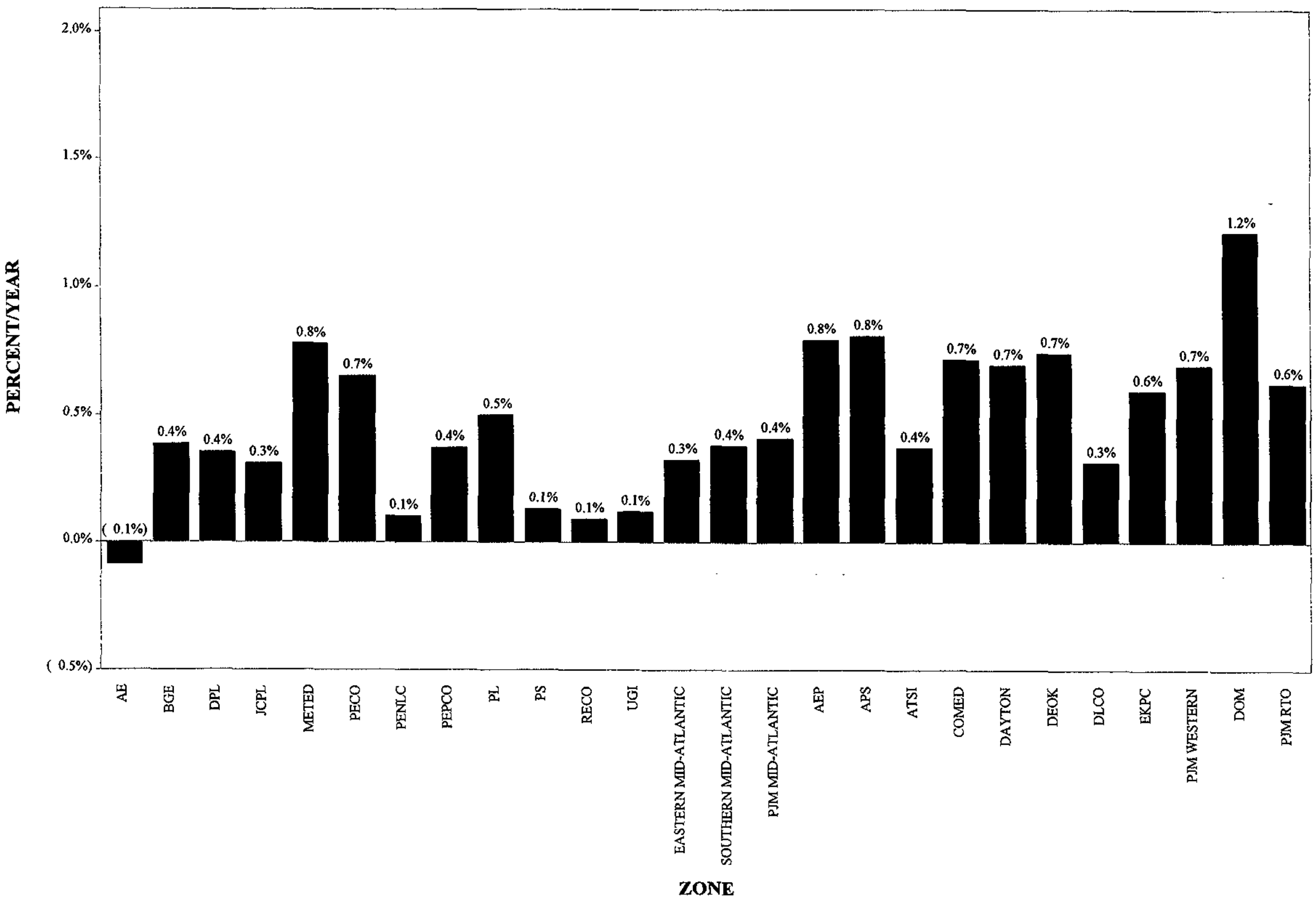
Avg real GDP growth from 2015 to 2030, %



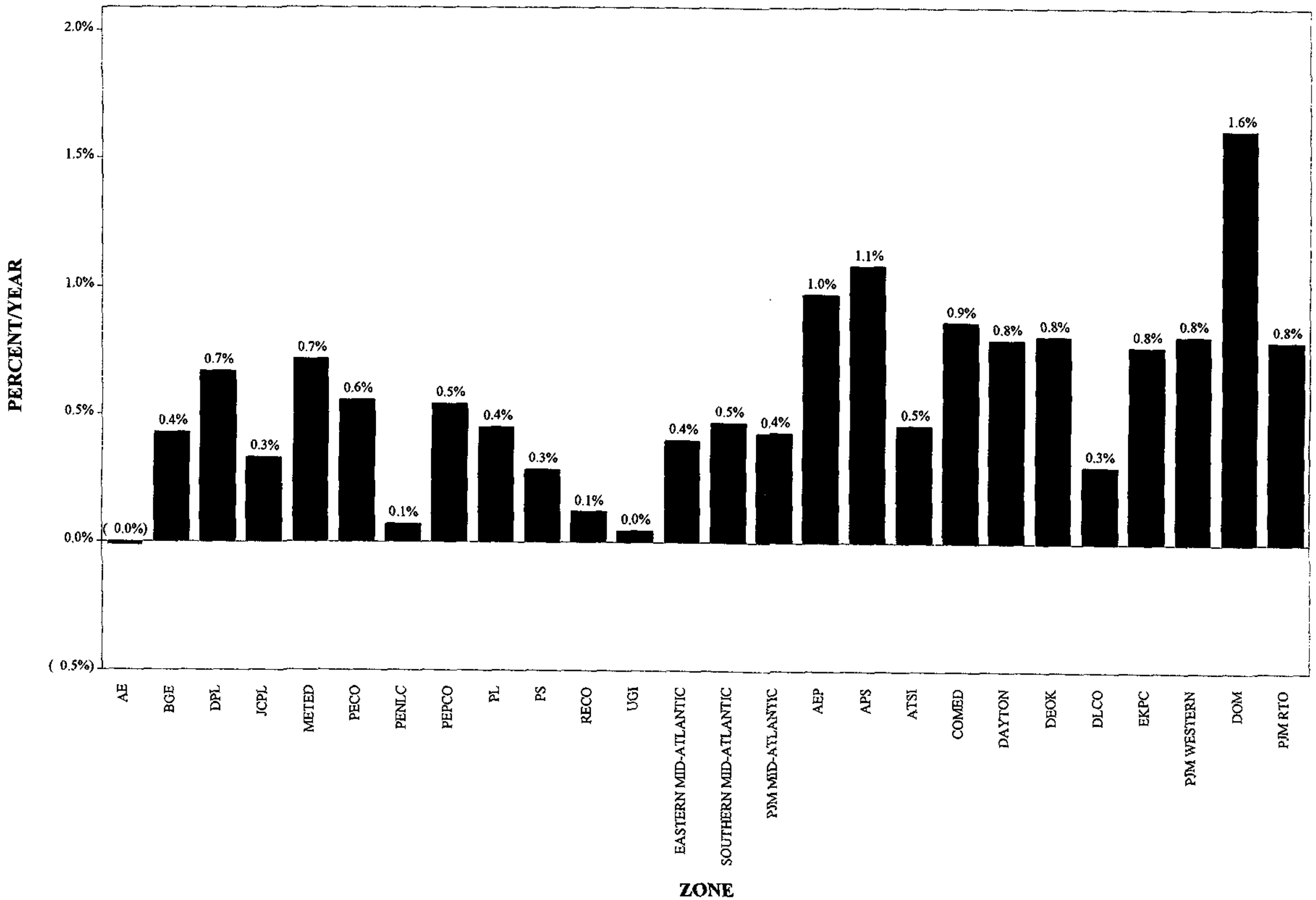
Sources: Census Bureau, Moody's Analytics

Of the 10 areas with the weakest increases in the number of households, five are in Ohio and four are in Pennsylvania. Eight of these areas will post net declines in the number of households. In Pennsylvania, the long-run decline of manufacturing is exacerbated by poor public sector finances that will weigh on local government employment as well as taxpayers.

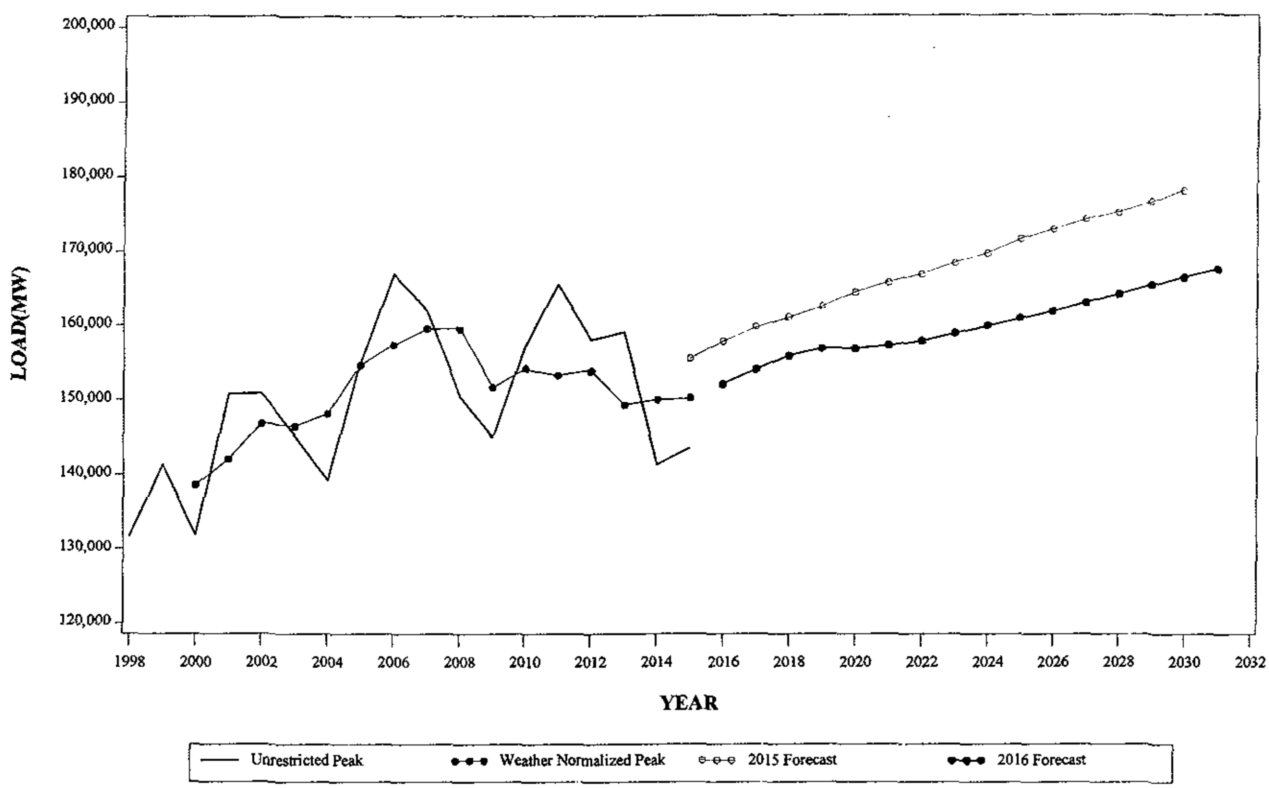
PJM SUMMER PEAK LOAD GROWTH RATE
2016 - 2026



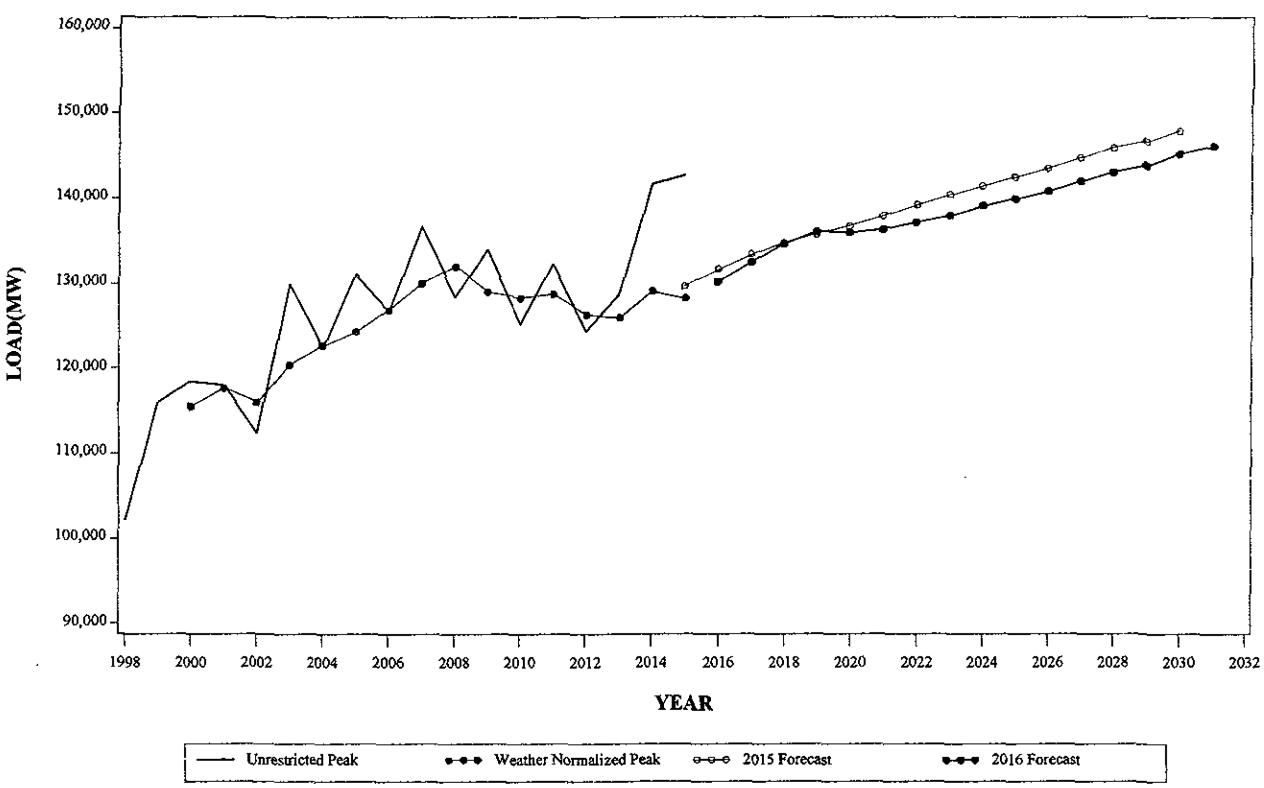
PJM WINTER PEAK LOAD GROWTH RATE
2016 - 2026



SUMMER PEAK DEMAND FOR PJM RTO GEOGRAPHIC ZONE



WINTER PEAK DEMAND FOR PJM RTO GEOGRAPHIC ZONE



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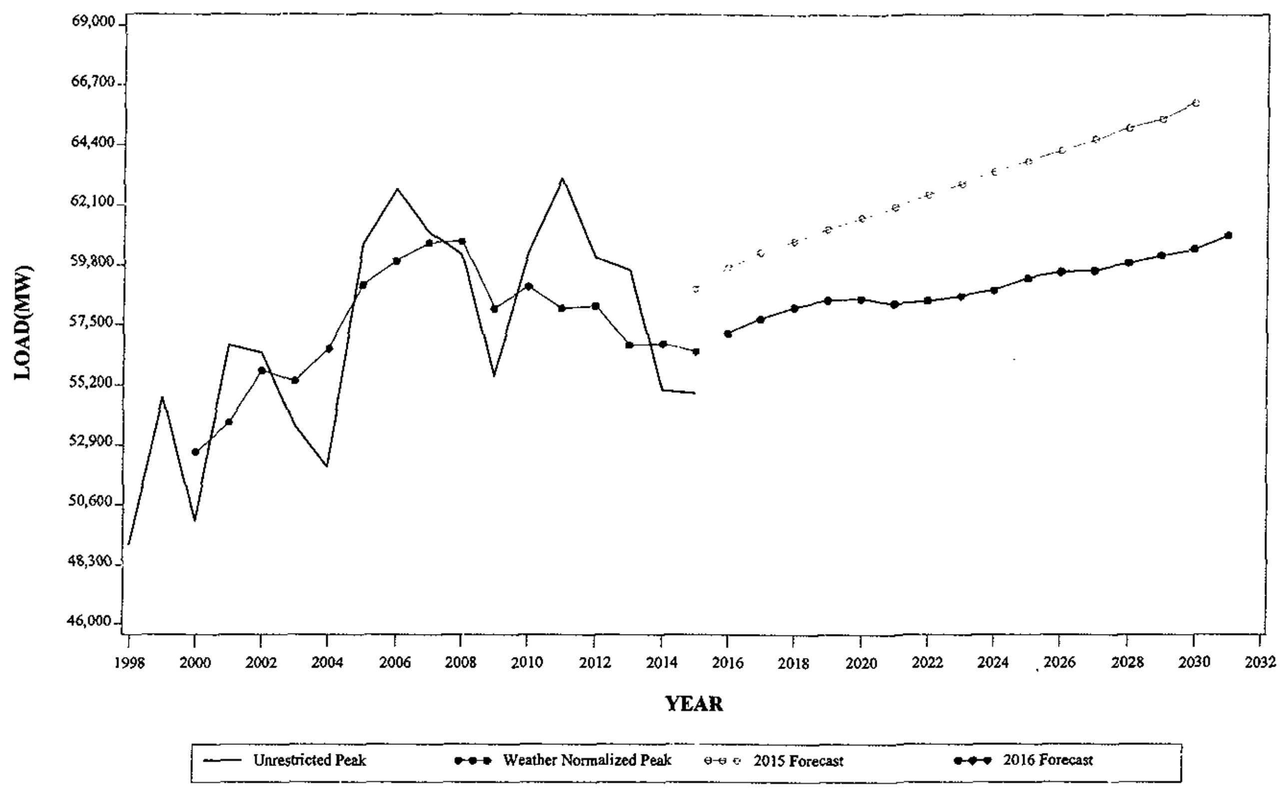

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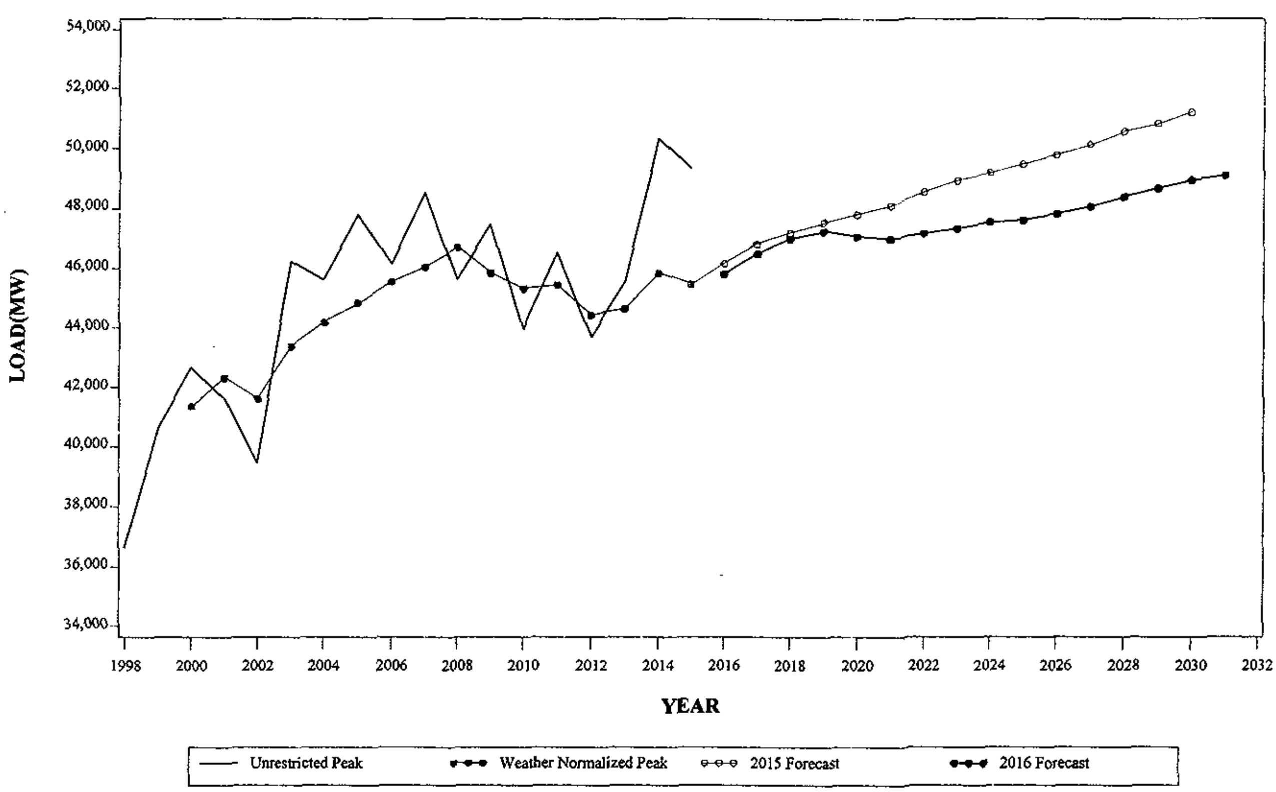

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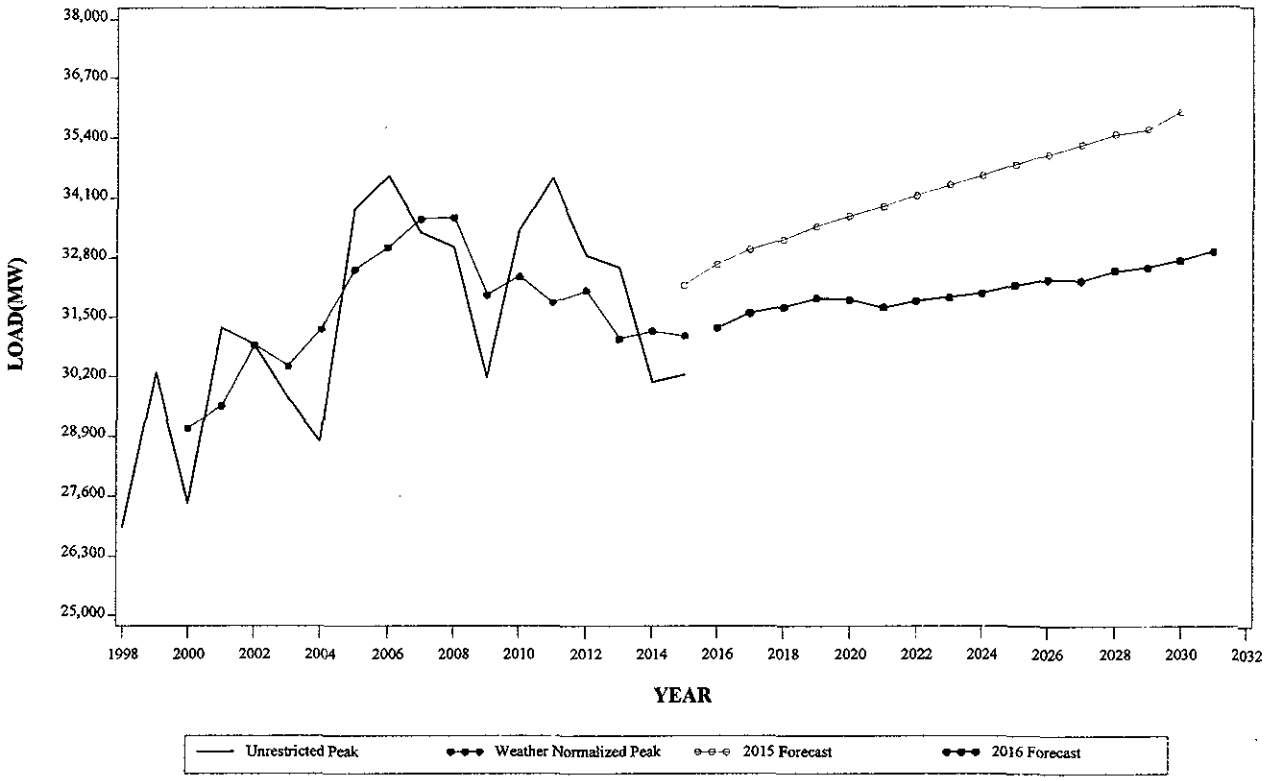
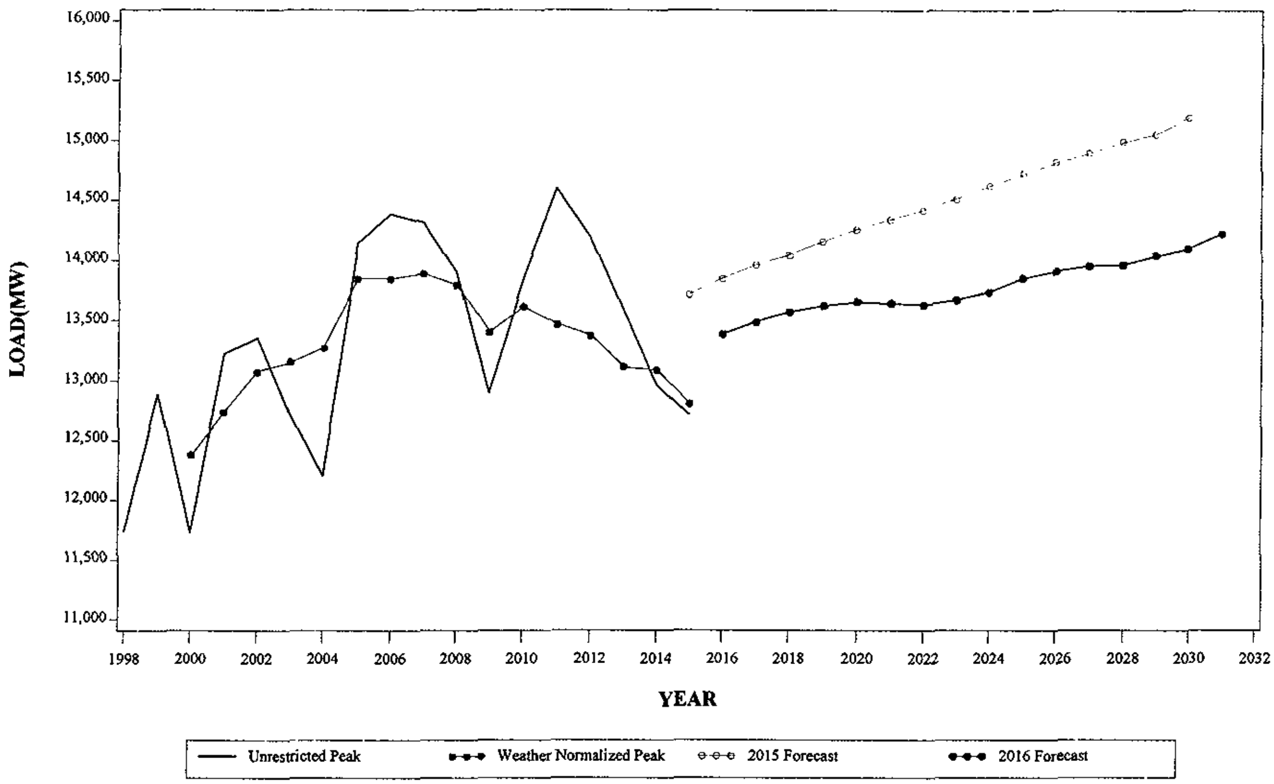
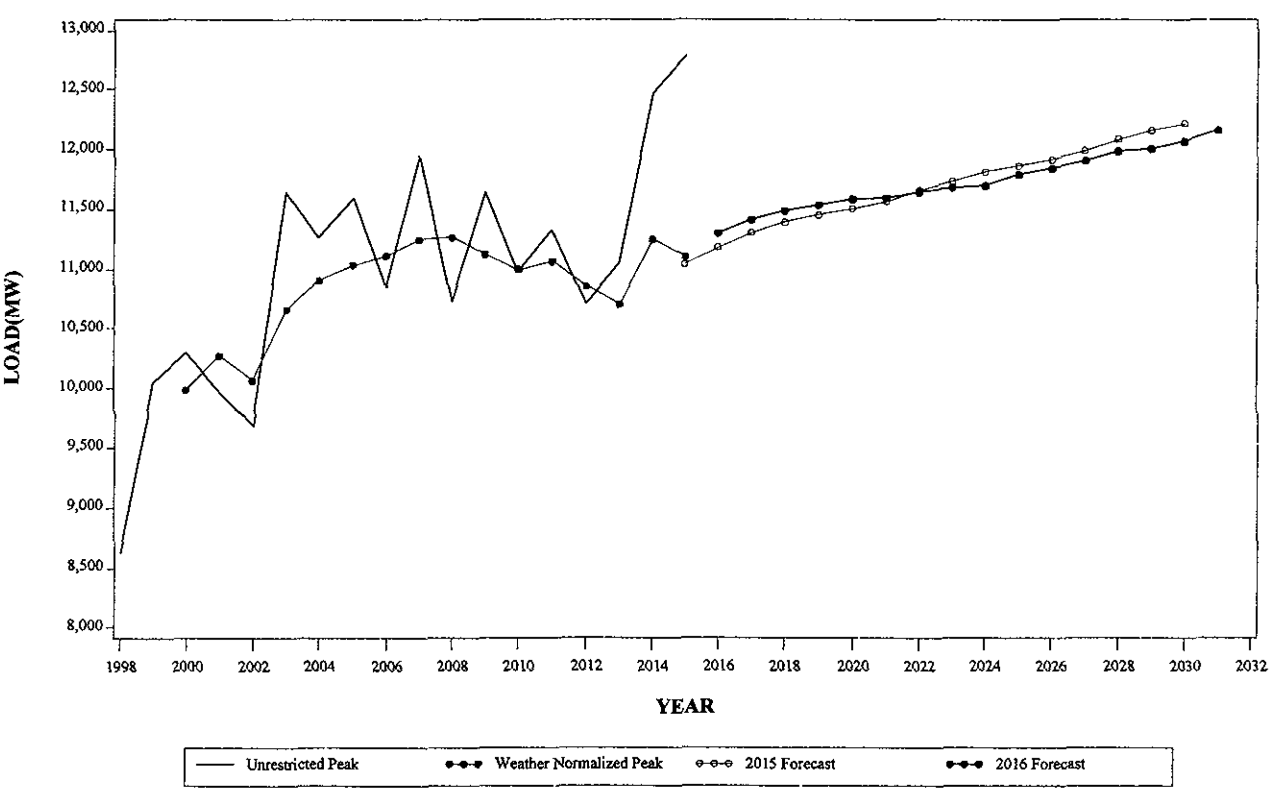


WINTER PEAK DEMAND FOR EASTERN MID-ATLANTIC GEOGRAPHIC ZONE

SUMMER PEAK DEMAND FOR SOUTHERN MID-ATLANTIC GEOGRAPHIC ZONE



WINTER PEAK DEMAND FOR SOUTHERN MID-ATLANTIC GEOGRAPHIC ZONE



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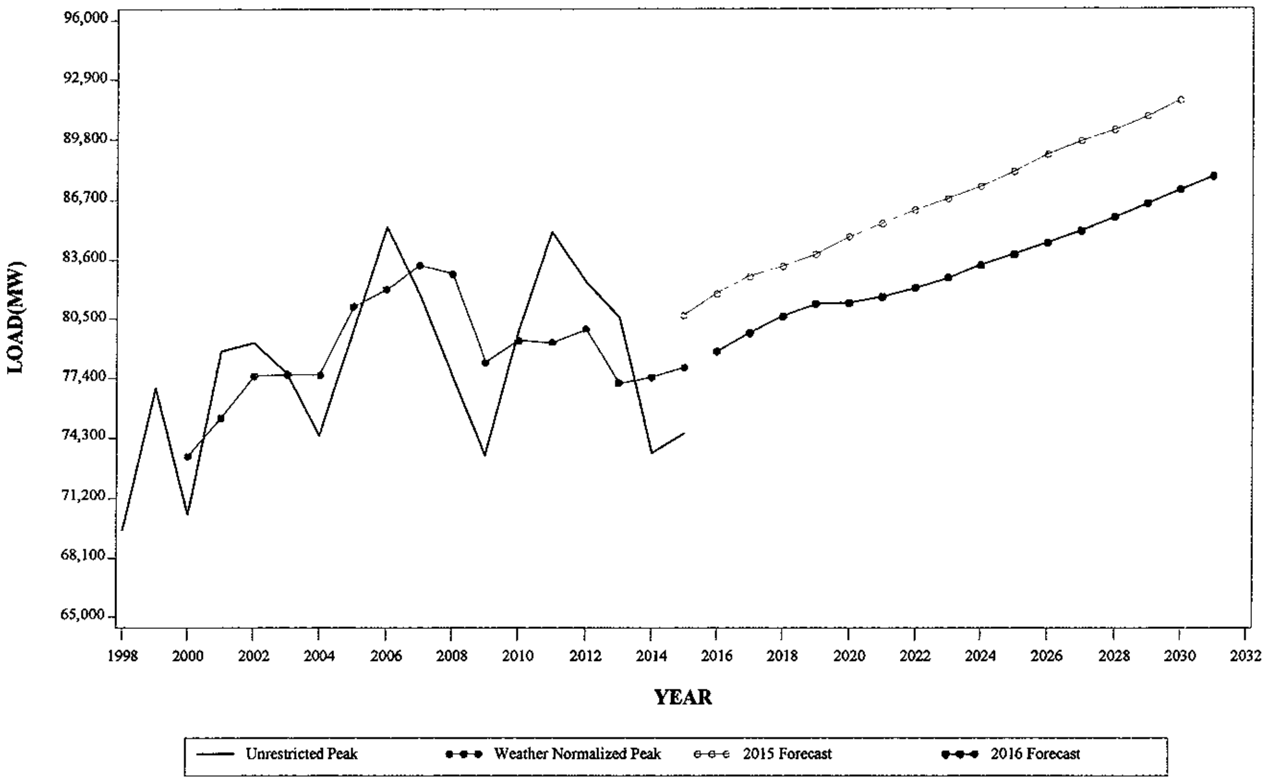
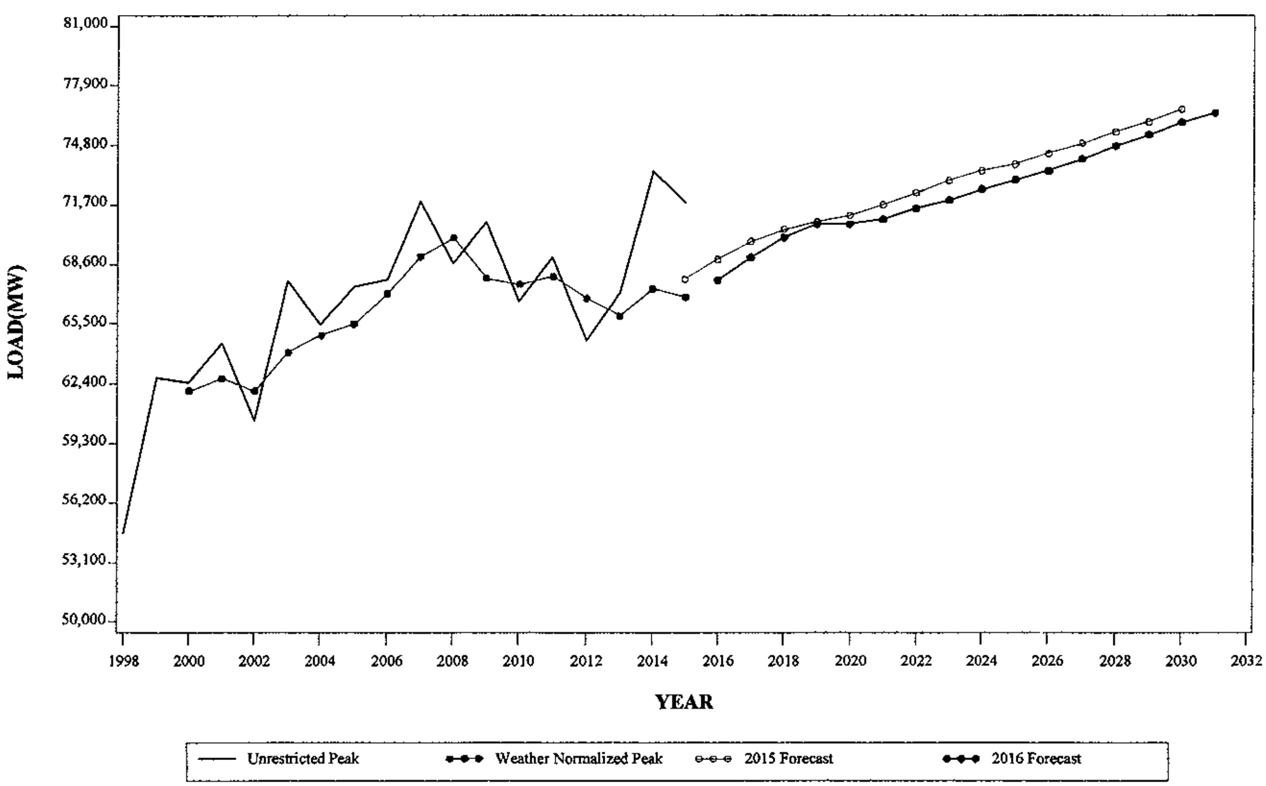


WINTER PEAK DEMAND FOR PJM WESTERN GEOGRAPHIC ZONE



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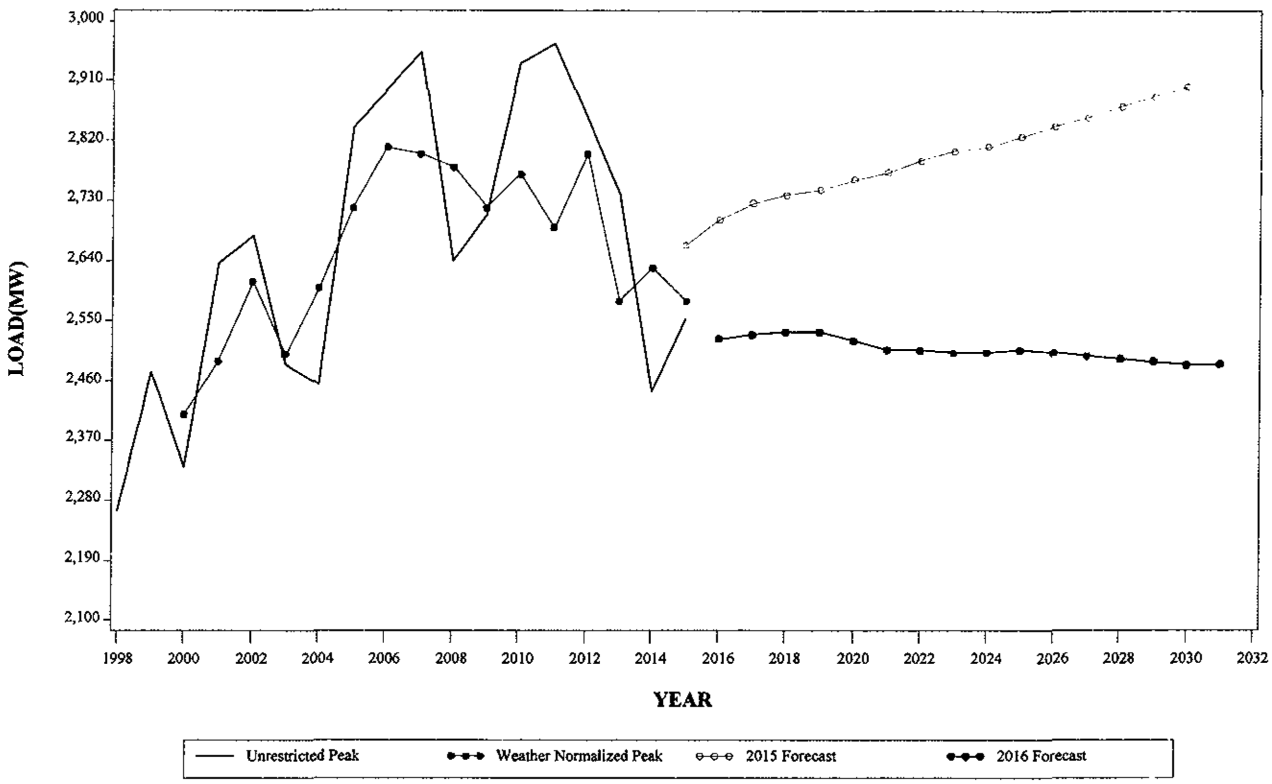
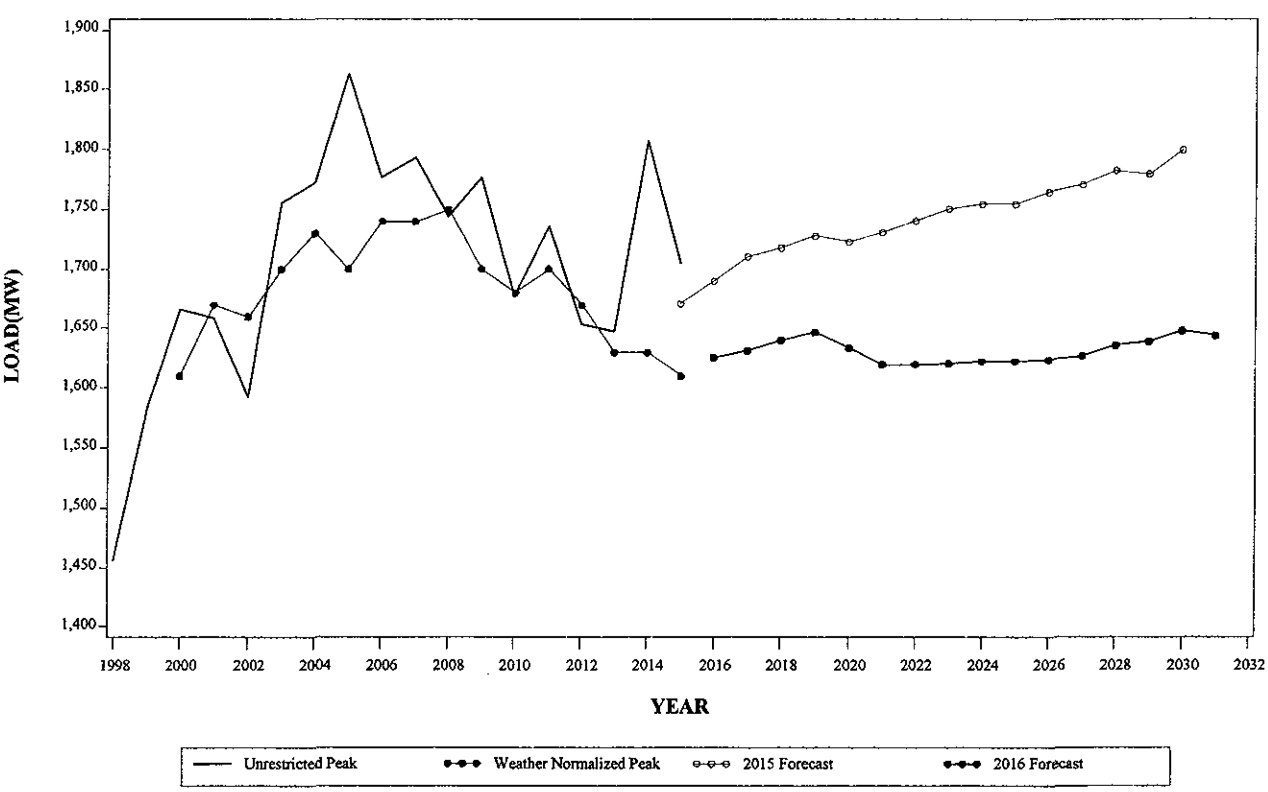
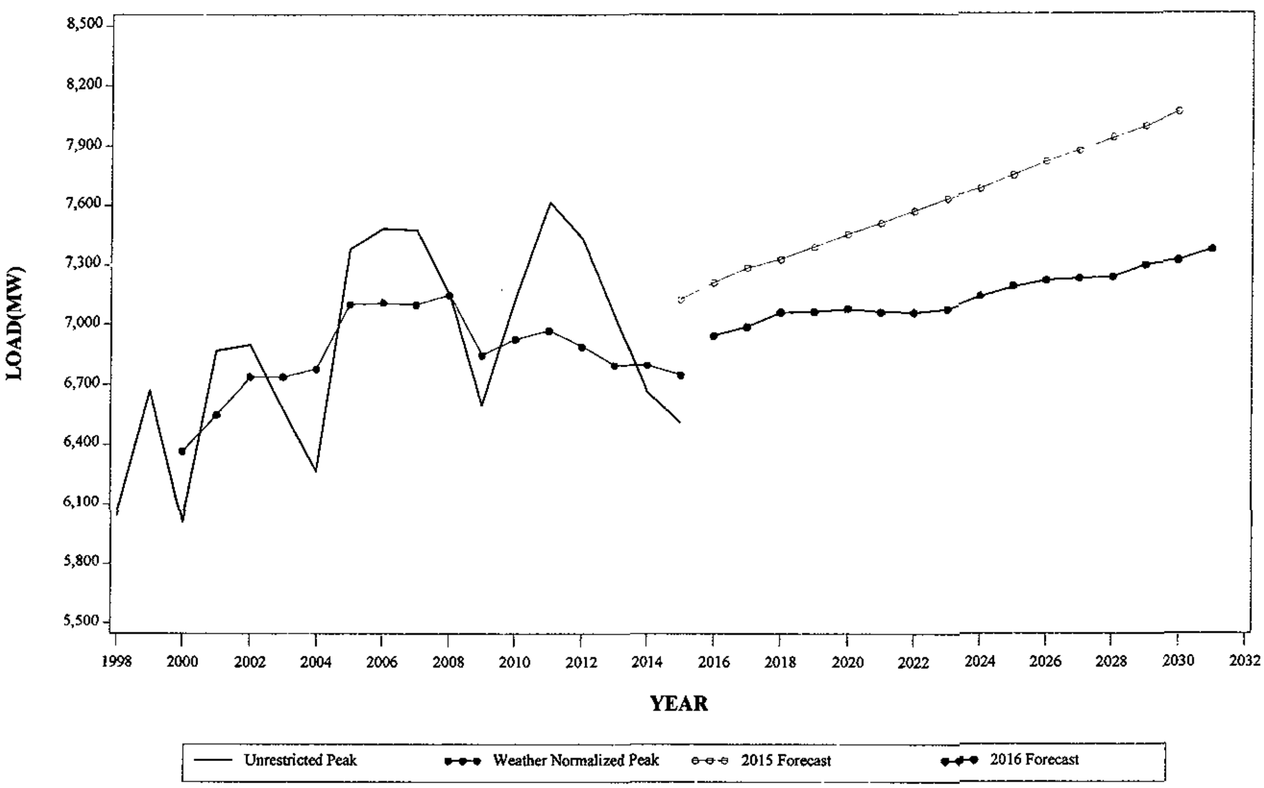


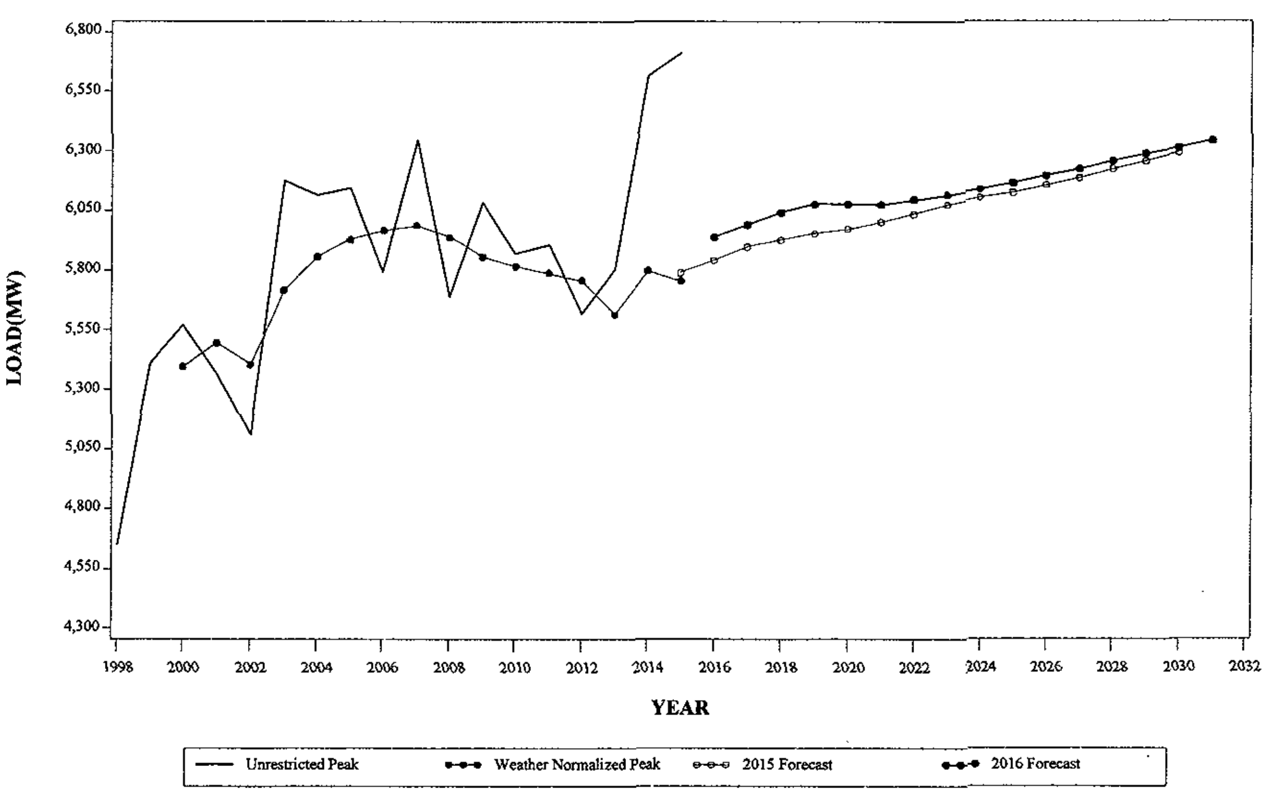
WINTER PEAK DEMAND FOR AE GEOGRAPHIC ZONE



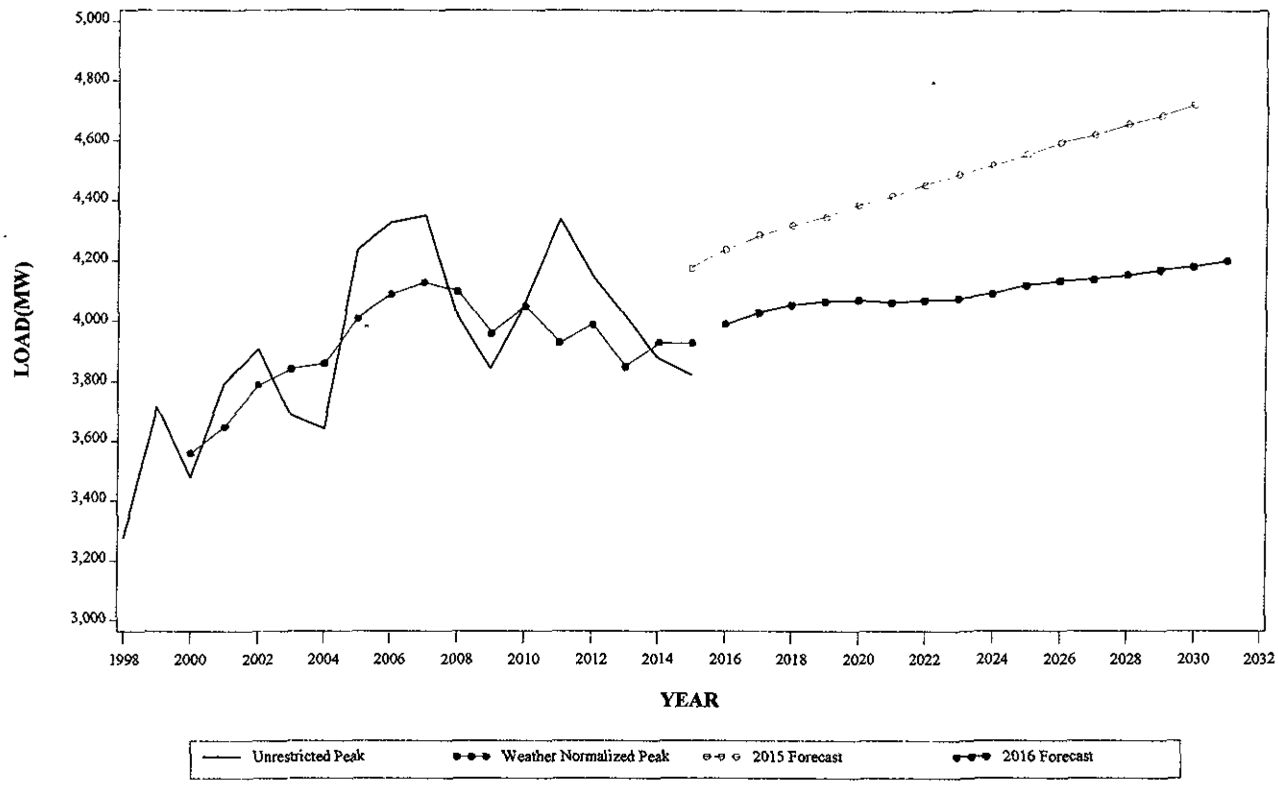
SUMMER PEAK DEMAND FOR BGE GEOGRAPHIC ZONE



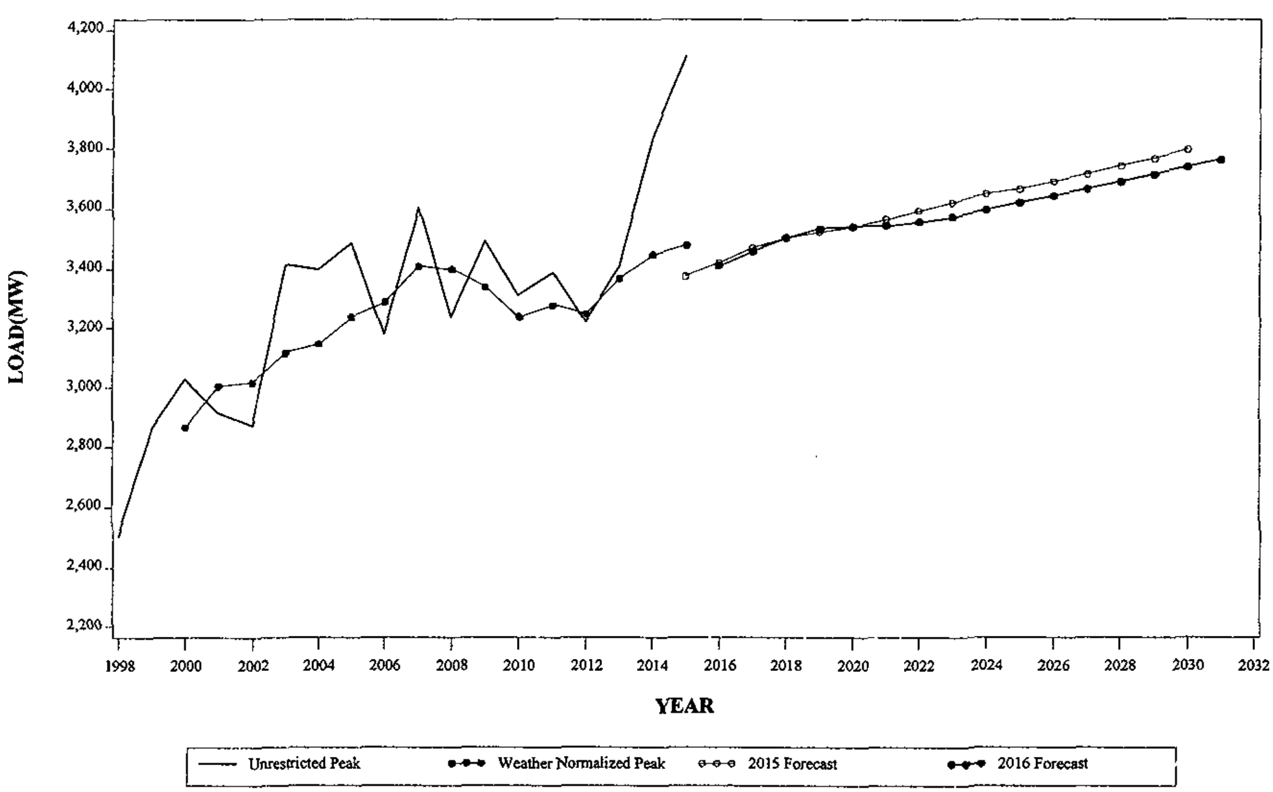
WINTER PEAK DEMAND FOR BGE GEOGRAPHIC ZONE



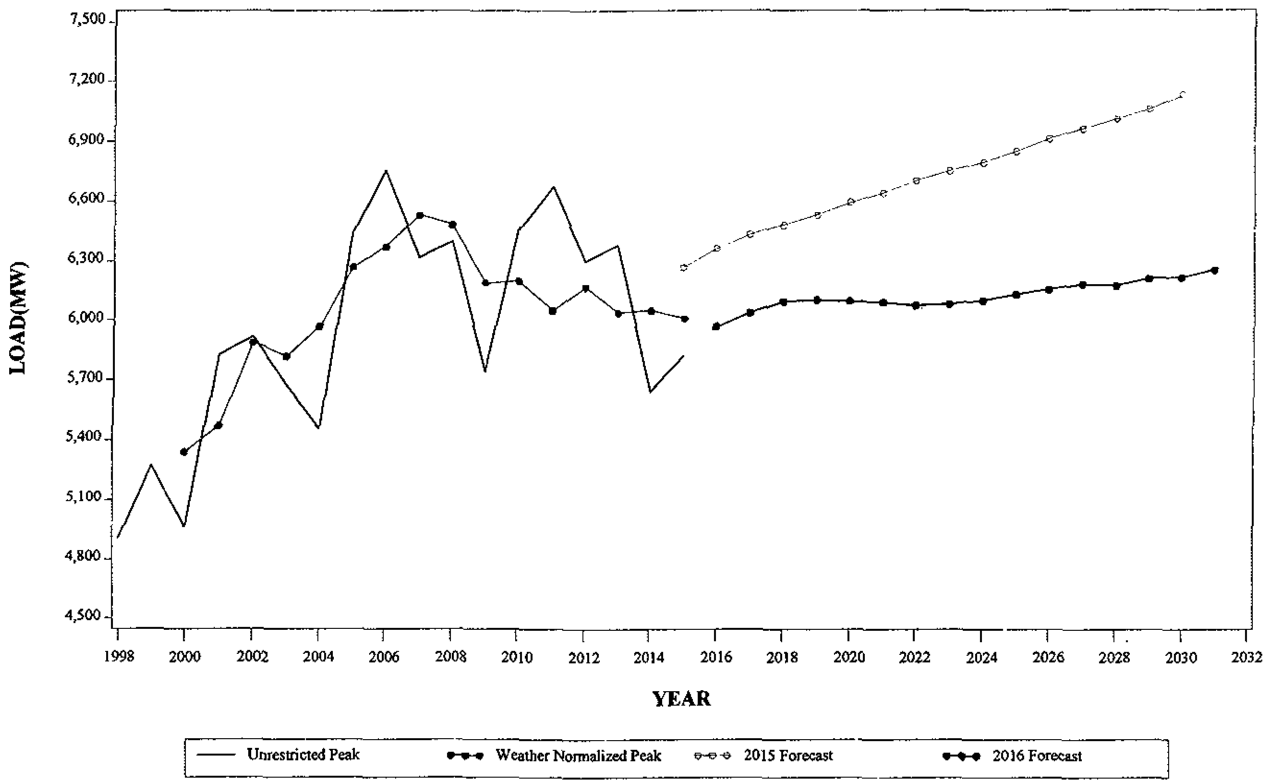
SUMMER PEAK DEMAND FOR DPL GEOGRAPHIC ZONE



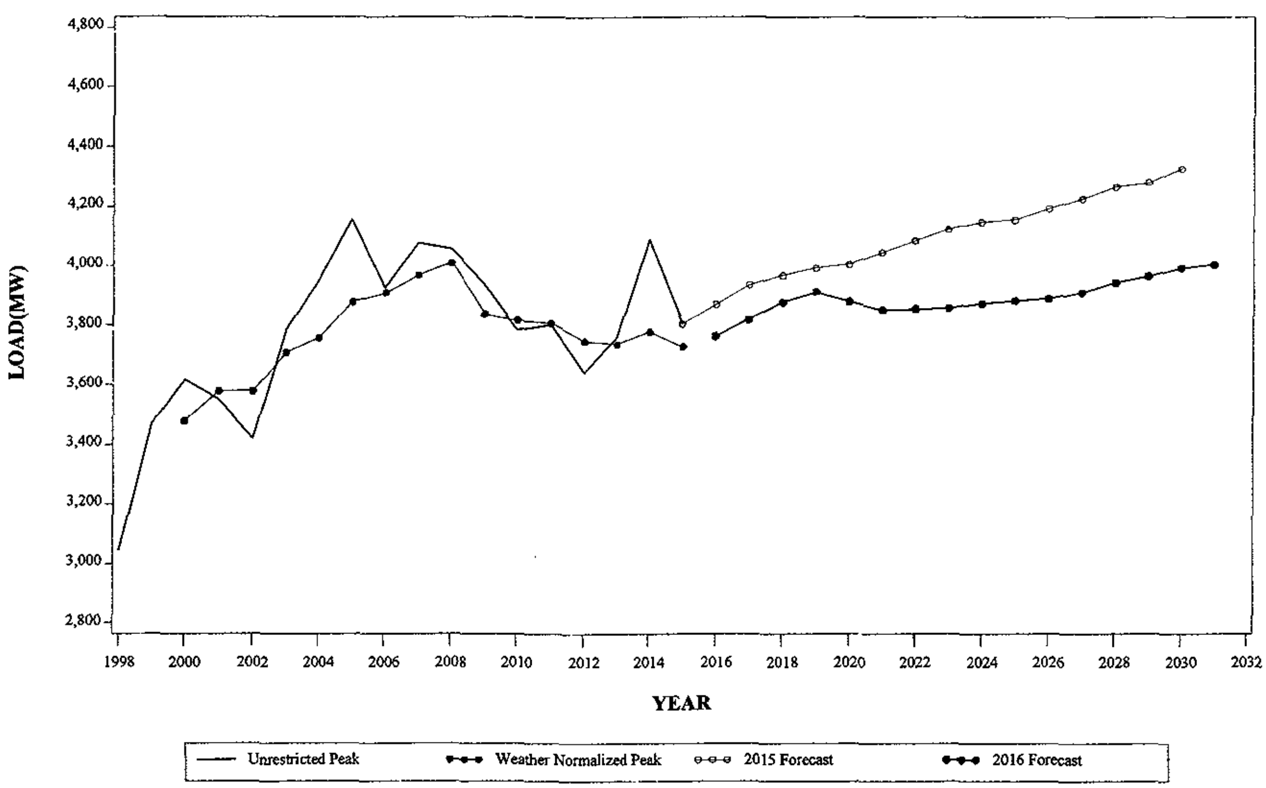
WINTER PEAK DEMAND FOR DPL GEOGRAPHIC ZONE



SUMMER PEAK DEMAND FOR JCPL
GEOGRAPHIC ZONE



WINTER PEAK DEMAND FOR JCPL
GEOGRAPHIC ZONE



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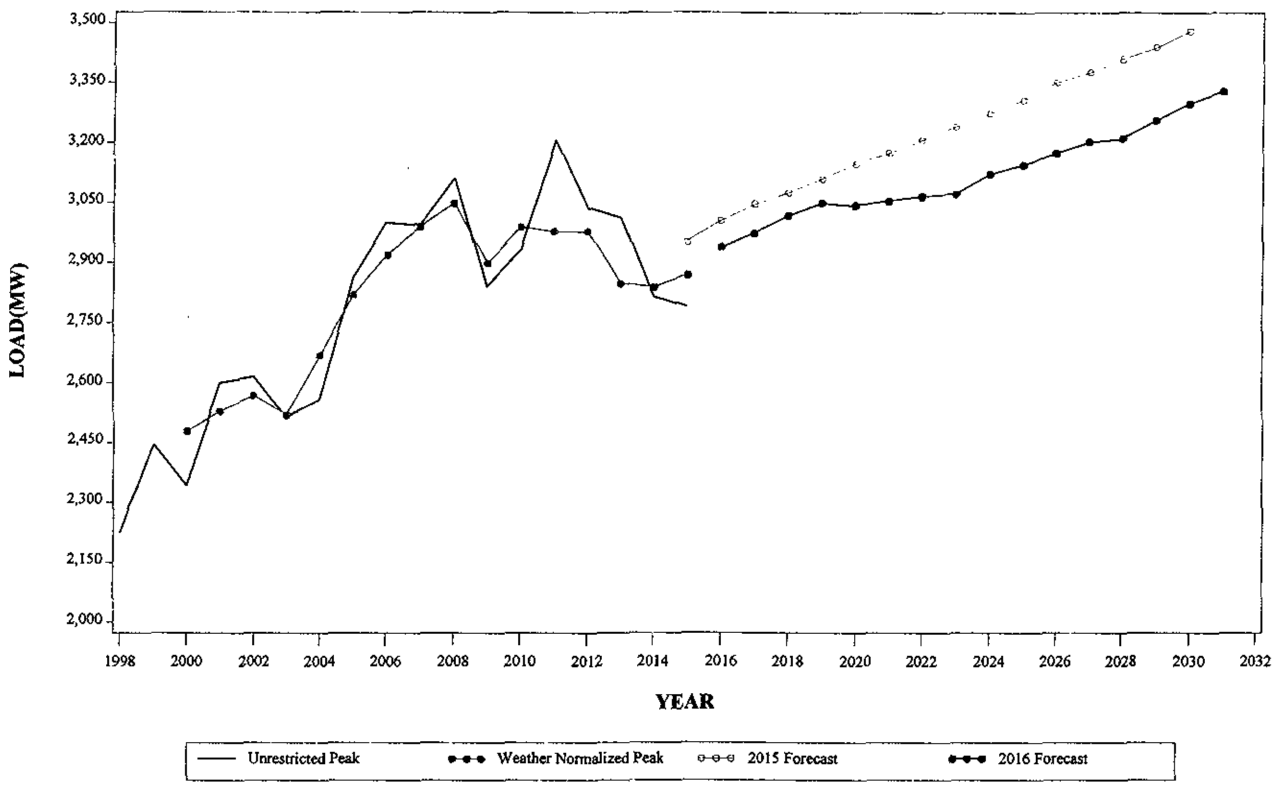

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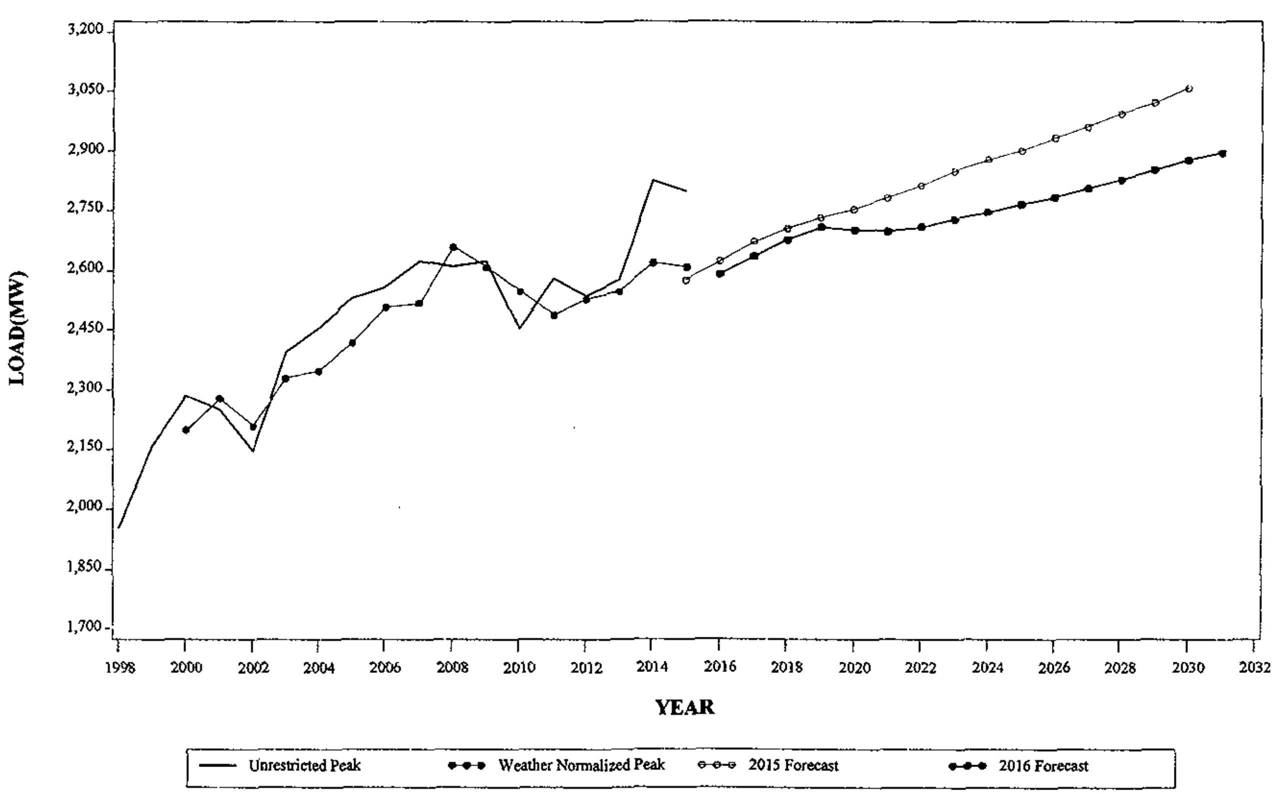

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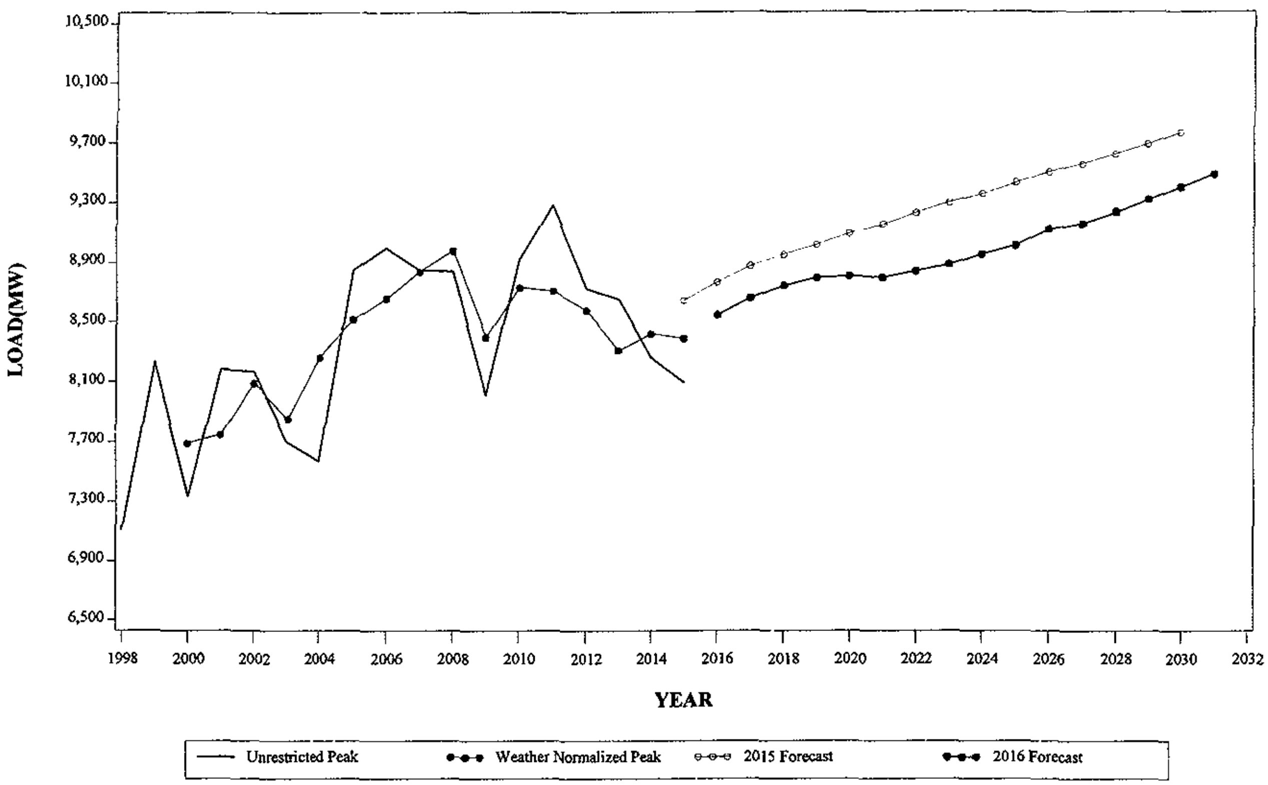

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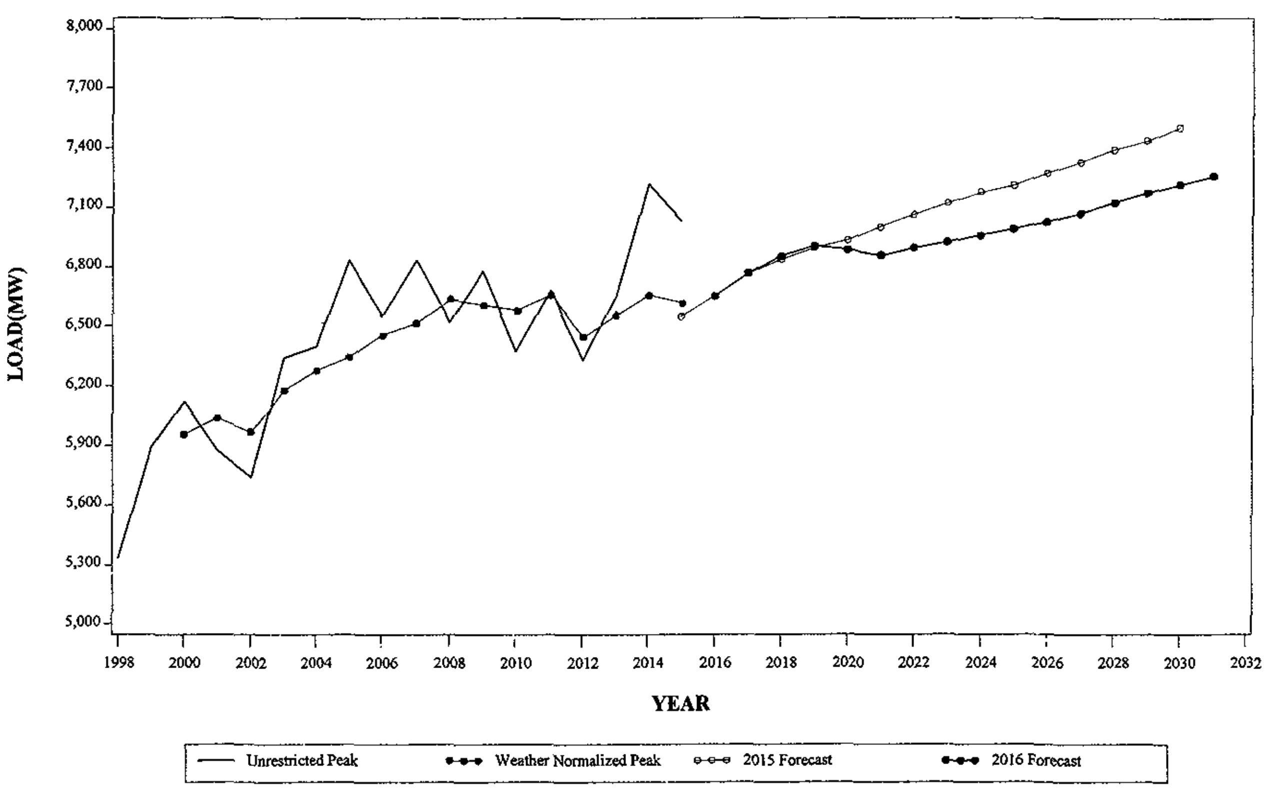
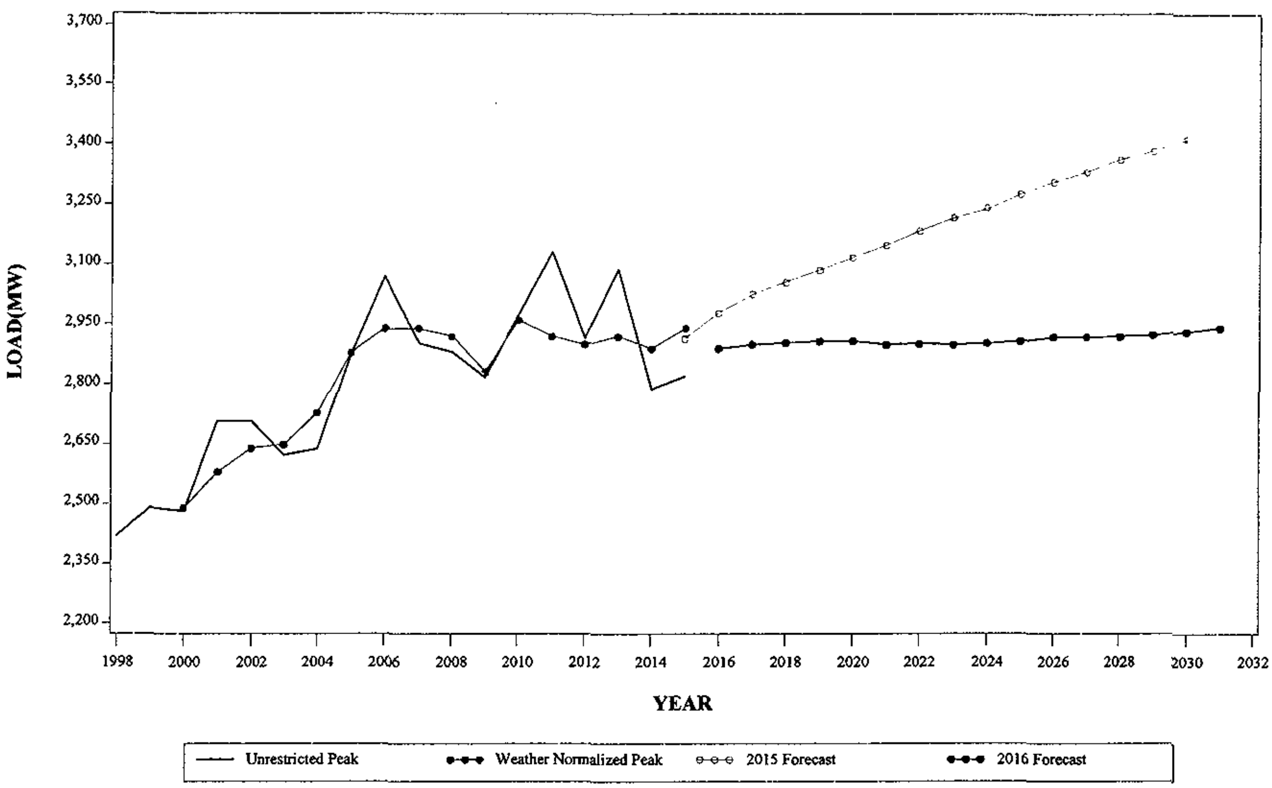


SUMMER PEAK DEMAND FOR PENLC
GEOGRAPHIC ZONE



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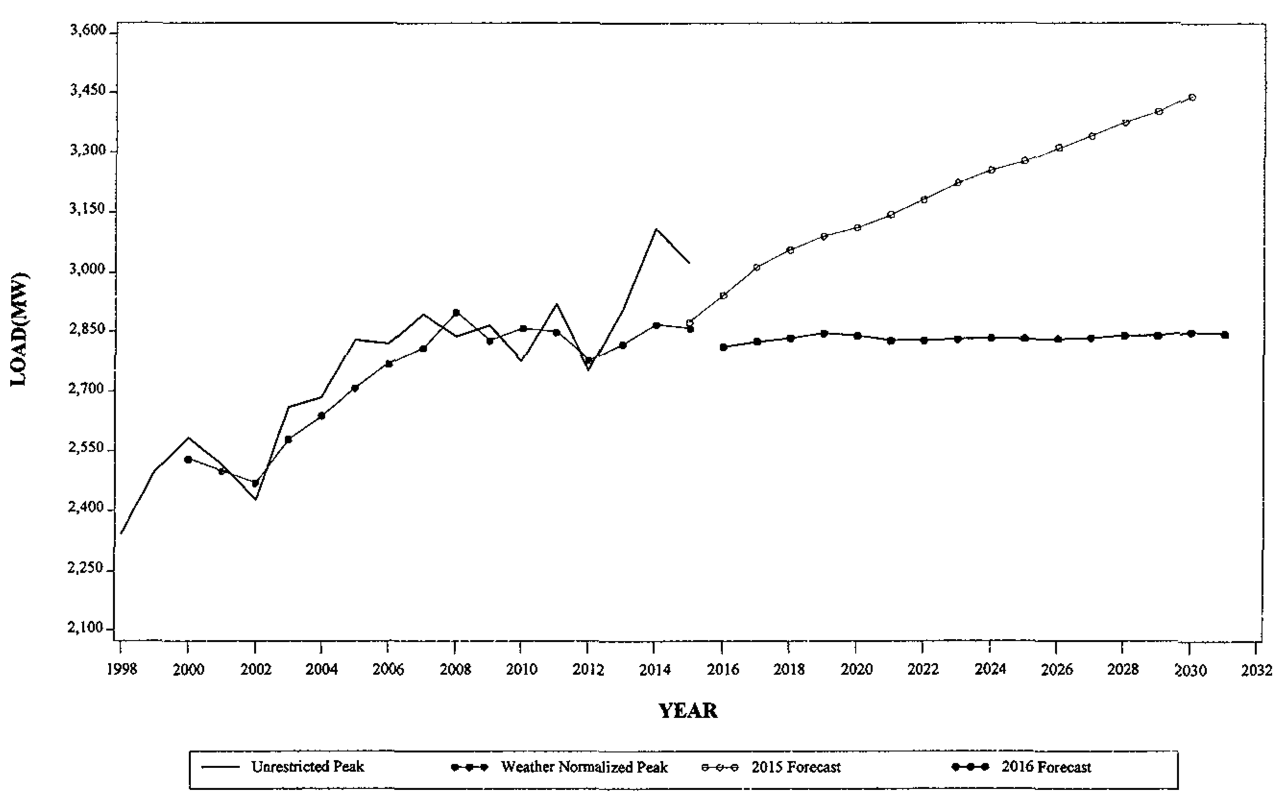

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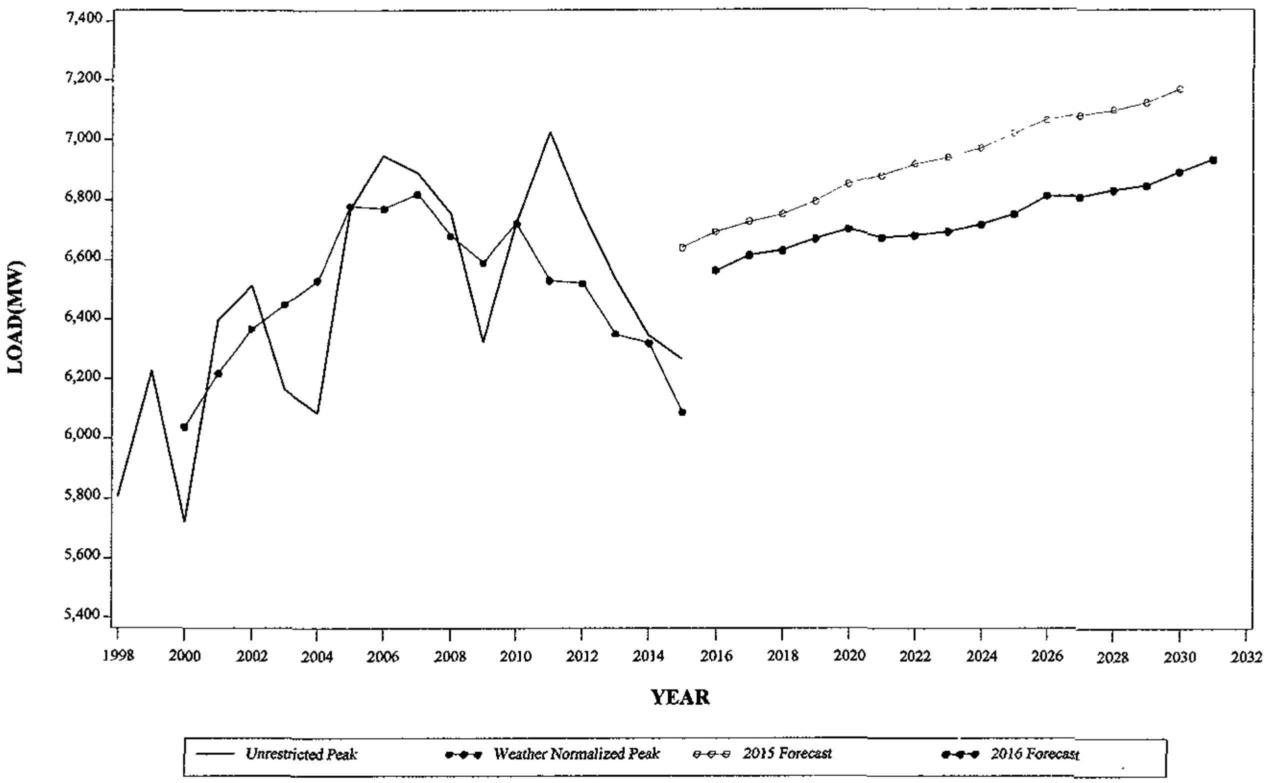

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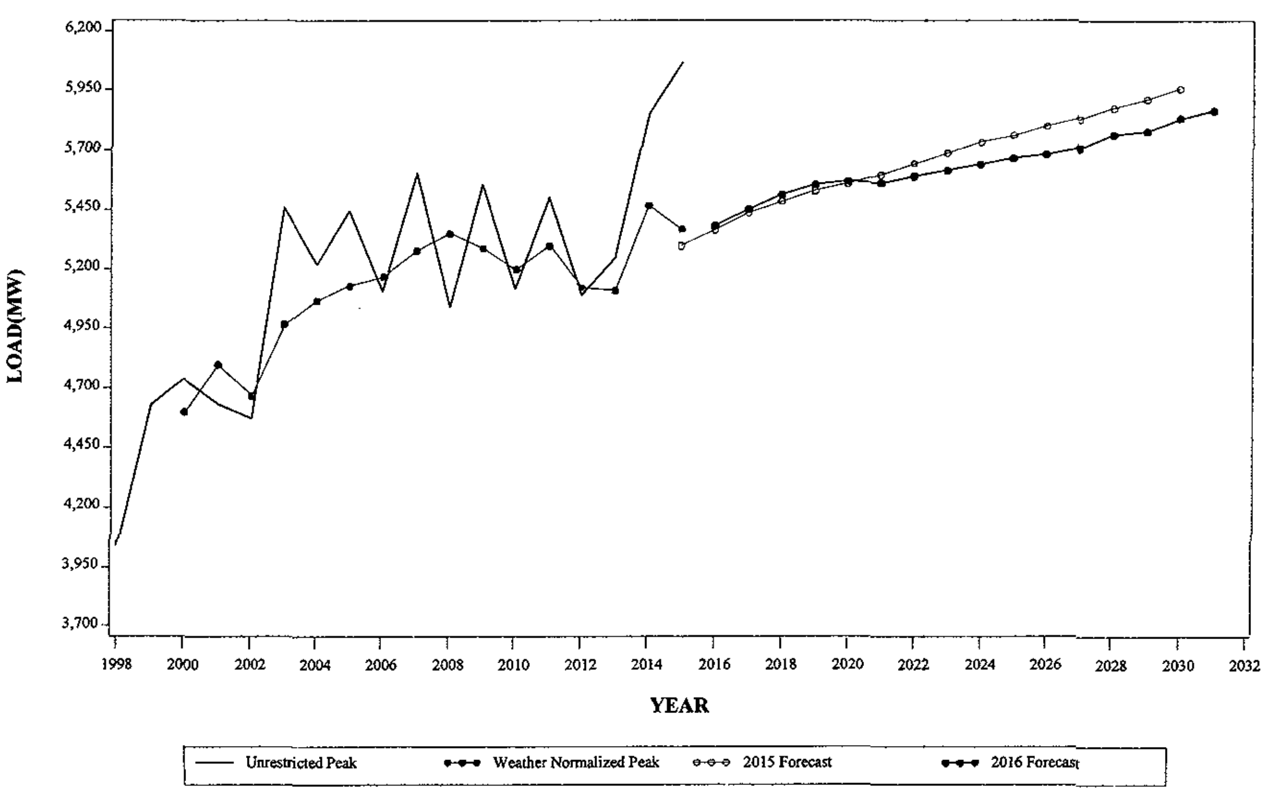

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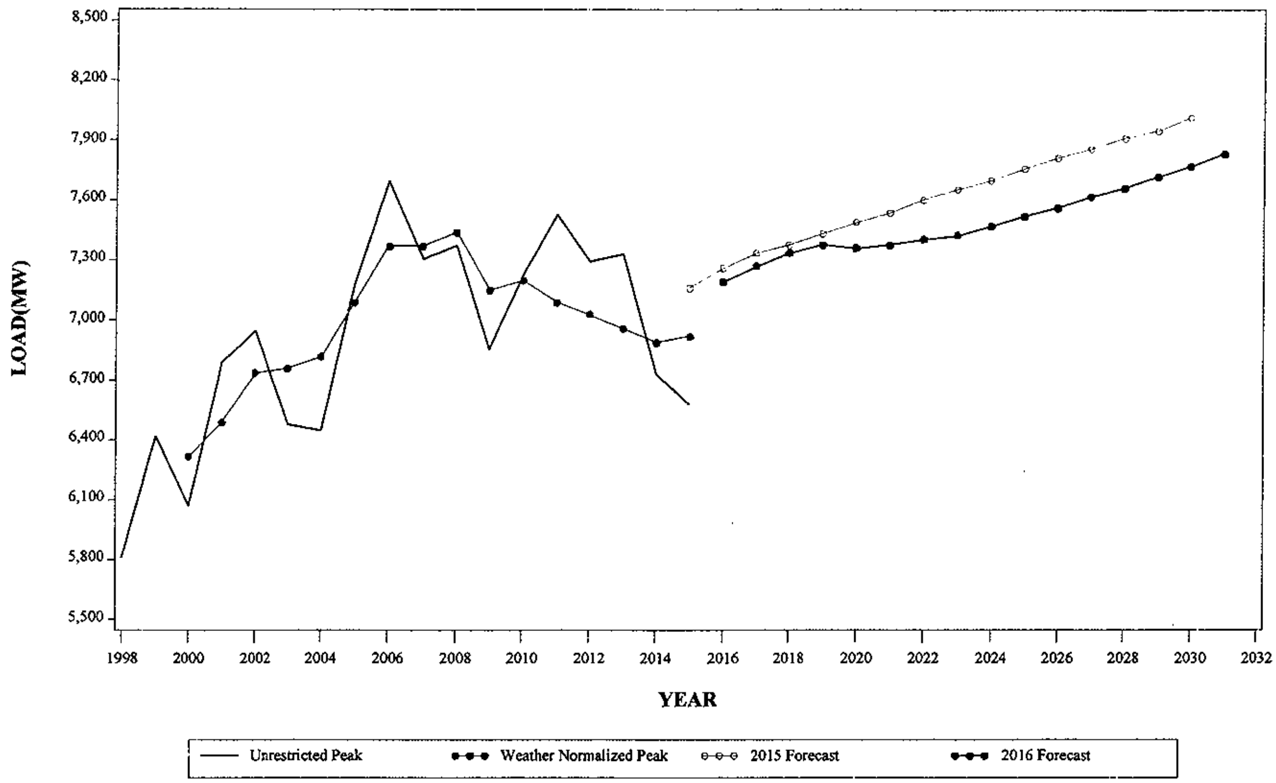
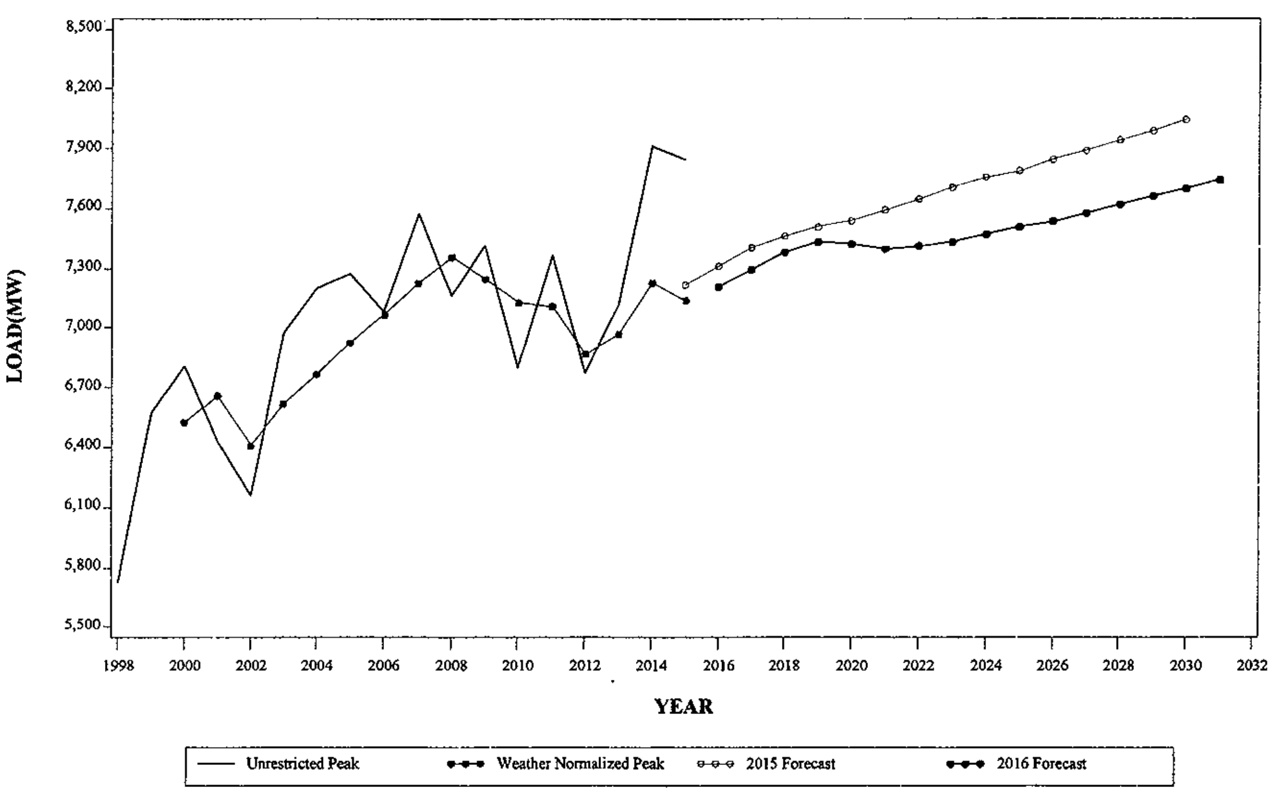
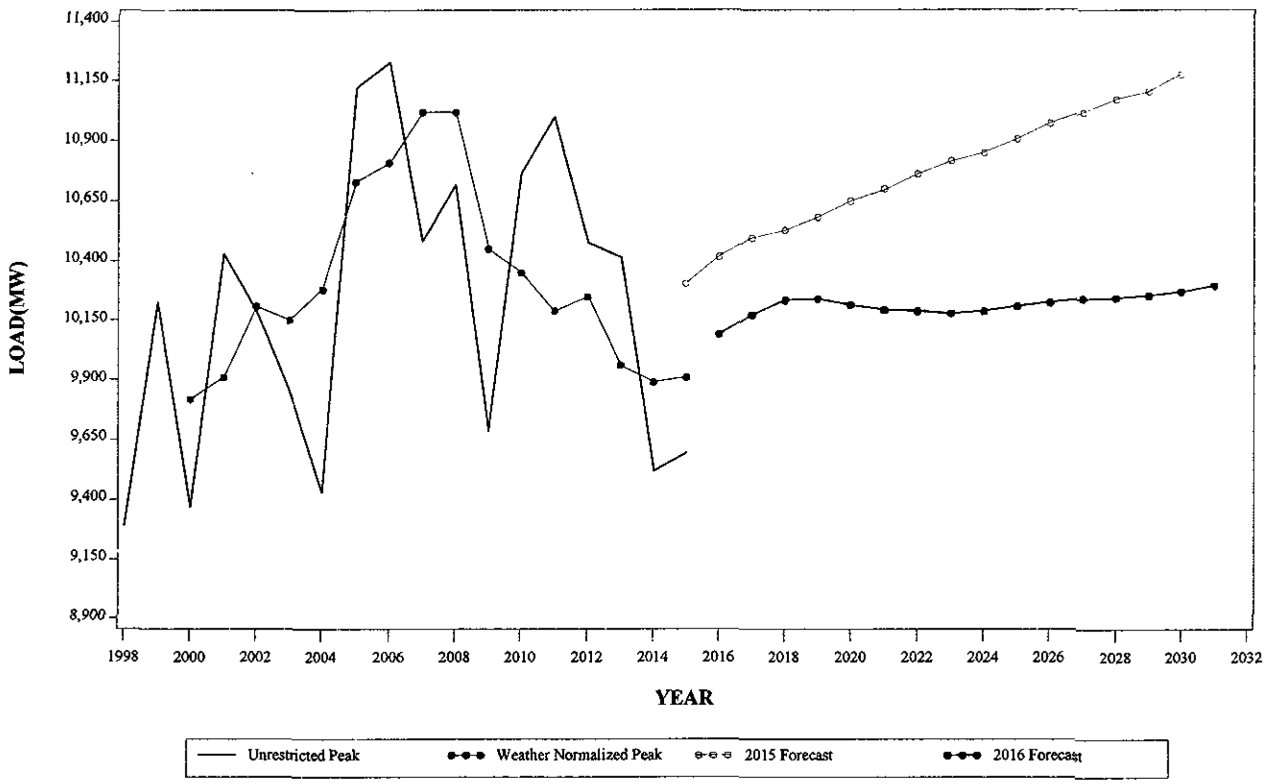


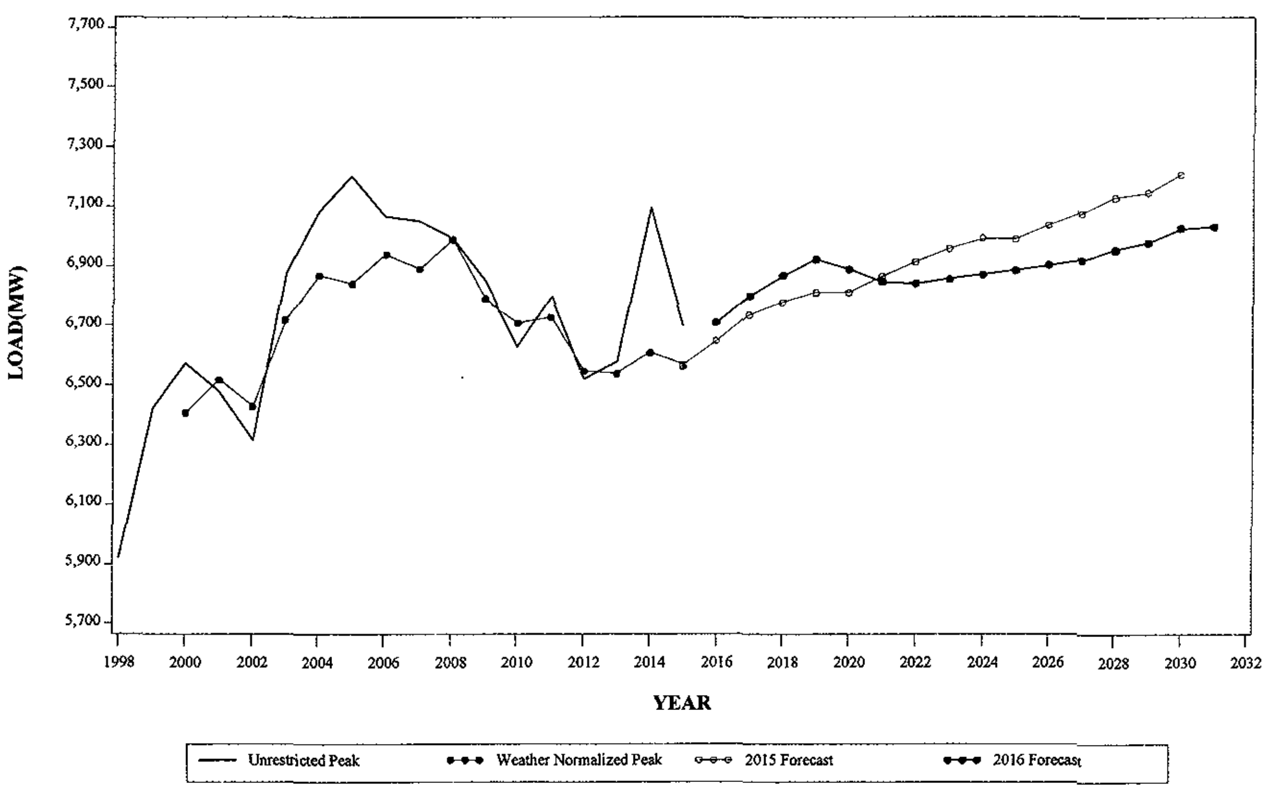
WINTER PEAK DEMAND FOR PL GEOGRAPHIC ZONE



**SUMMER PEAK DEMAND FOR PS
GEOGRAPHIC ZONE**



**WINTER PEAK DEMAND FOR PS
GEOGRAPHIC ZONE**



SUMMER PEAK DEMAND FOR RECO
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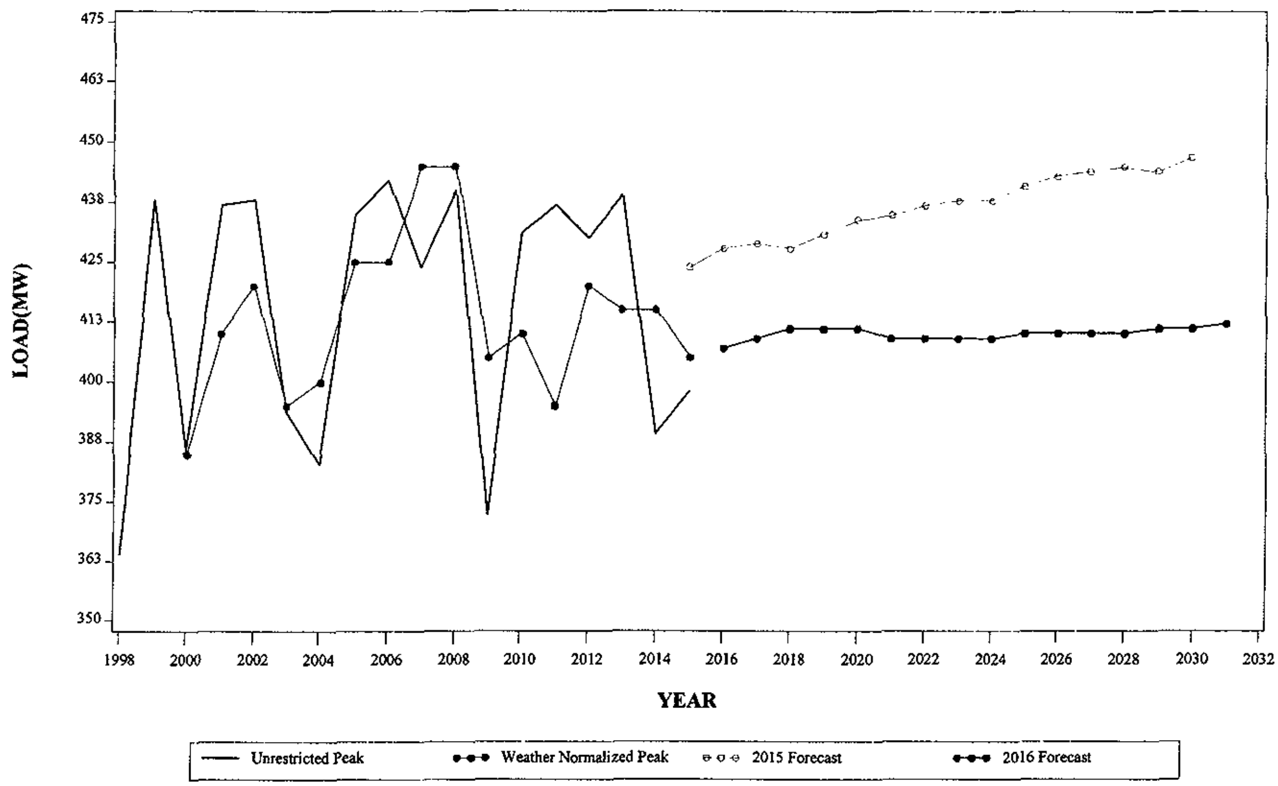
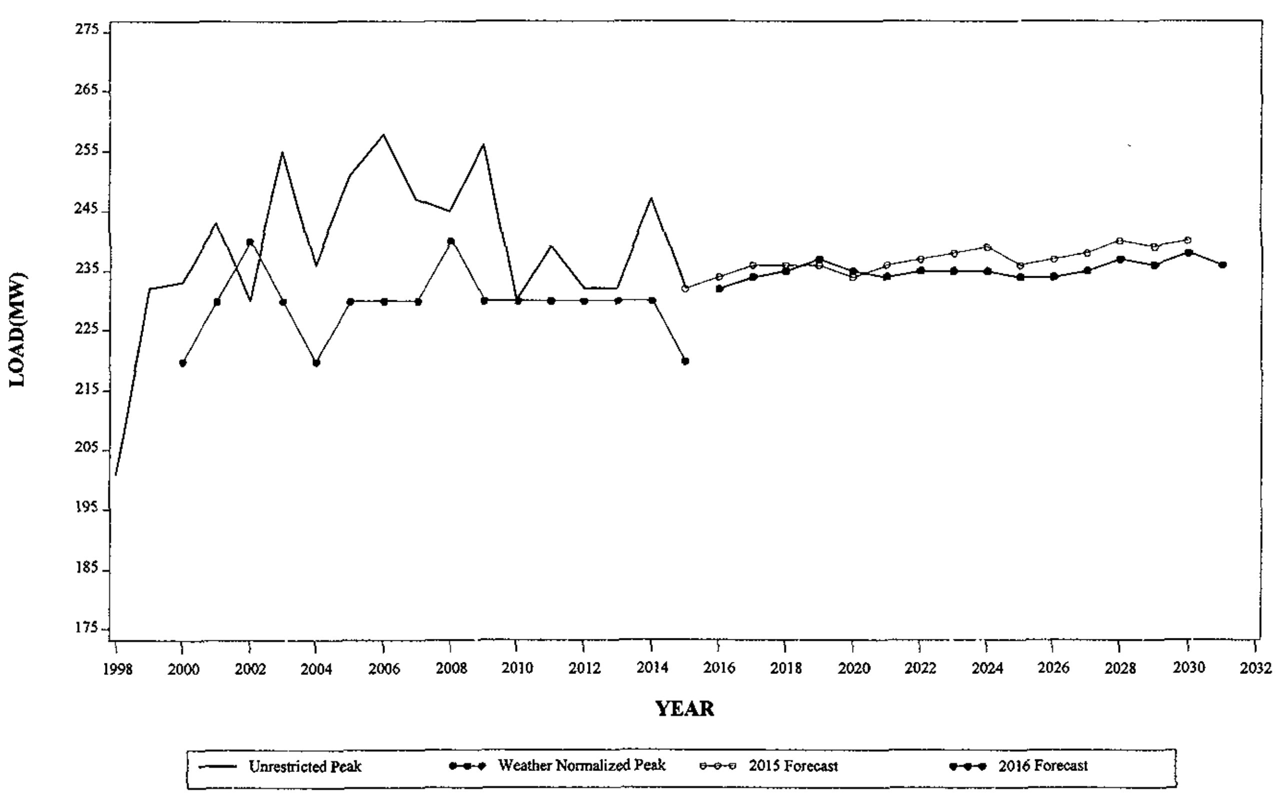
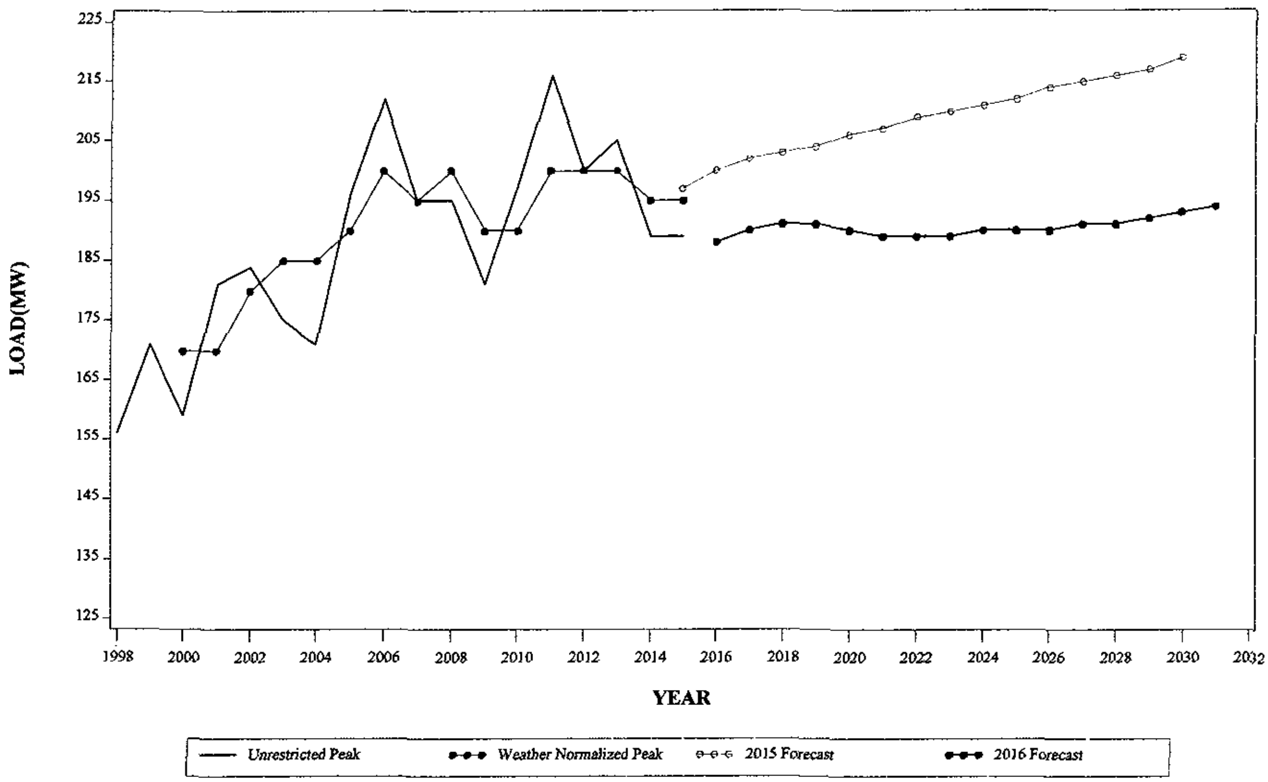


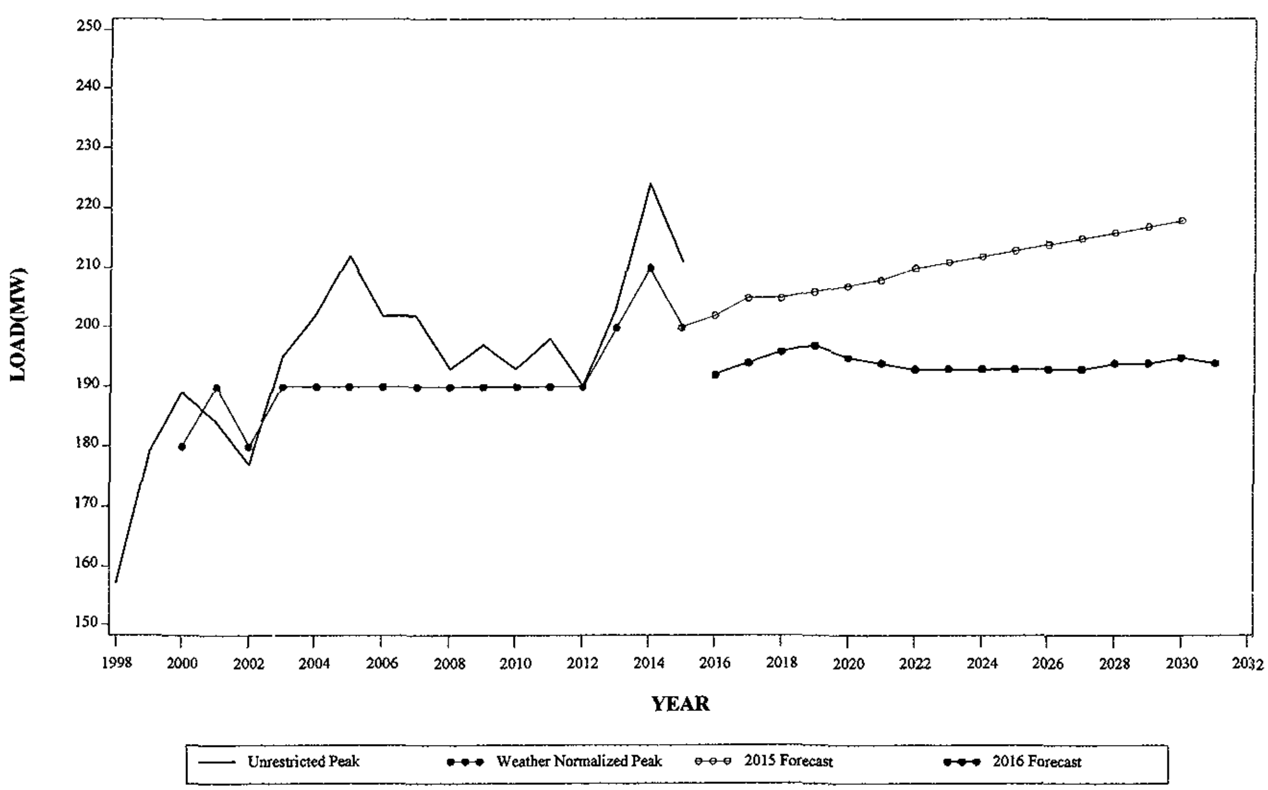
WINTER PEAK DEMAND FOR RECO
GEOGRAPHIC ZONE



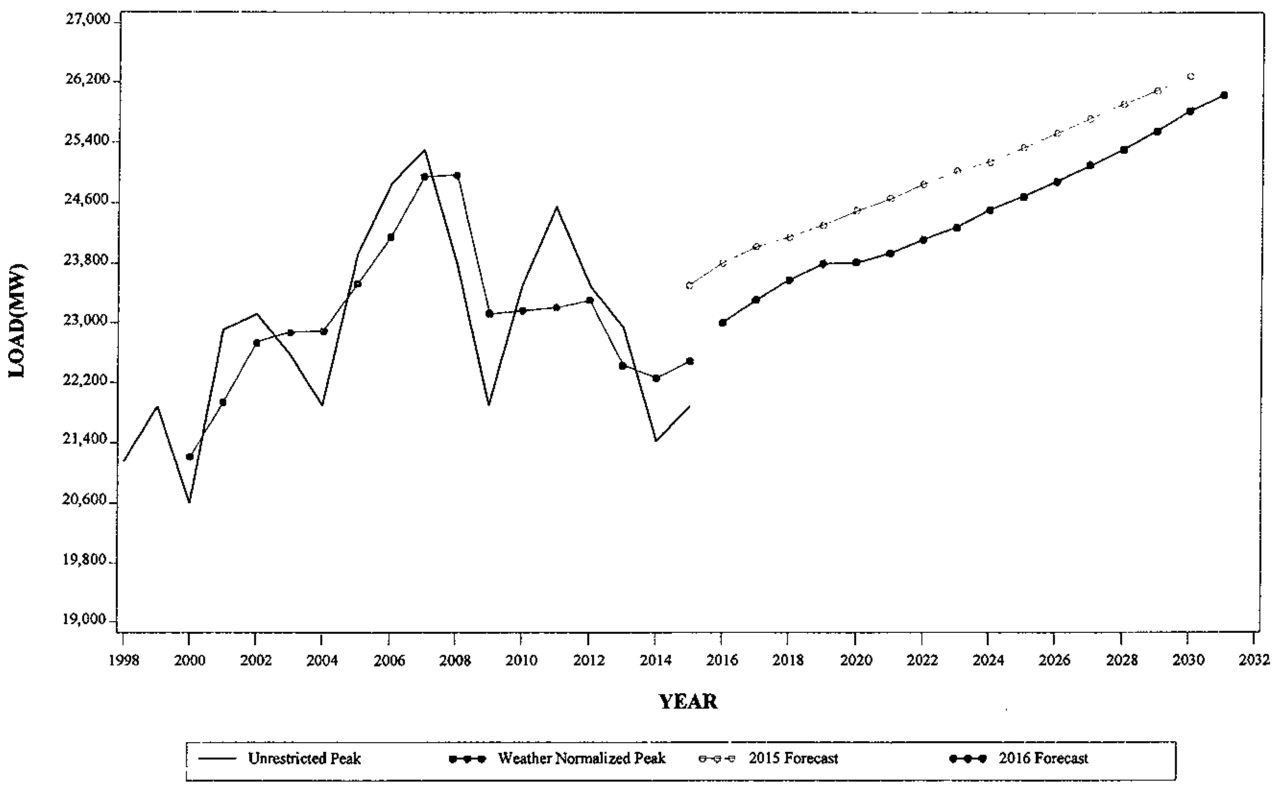
SUMMER PEAK DEMAND FOR UGI GEOGRAPHIC ZONE



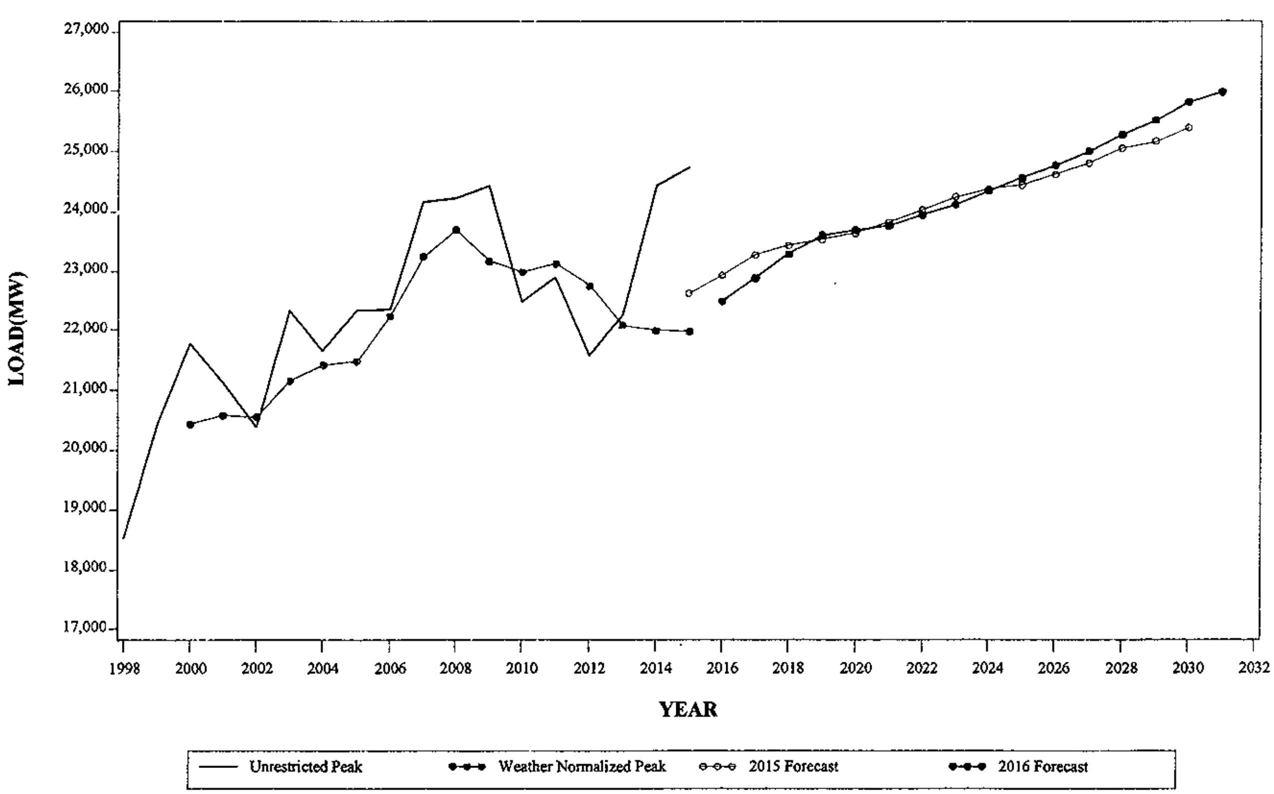
WINTER PEAK DEMAND FOR UGI GEOGRAPHIC ZONE



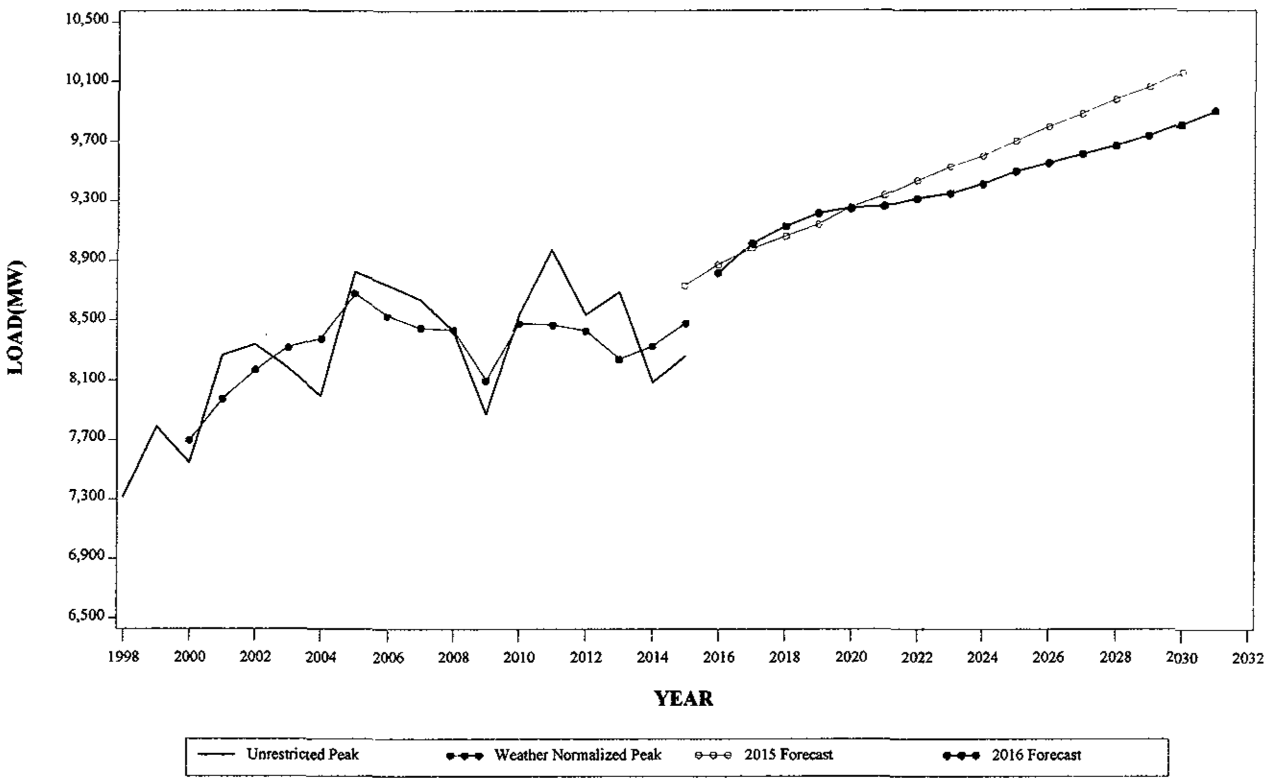
SUMMER PEAK DEMAND FOR AEP
GEOGRAPHIC ZONE



WINTER PEAK DEMAND FOR AEP
GEOGRAPHIC ZONE



SUMMER PEAK DEMAND FOR APS GEOGRAPHIC ZONE



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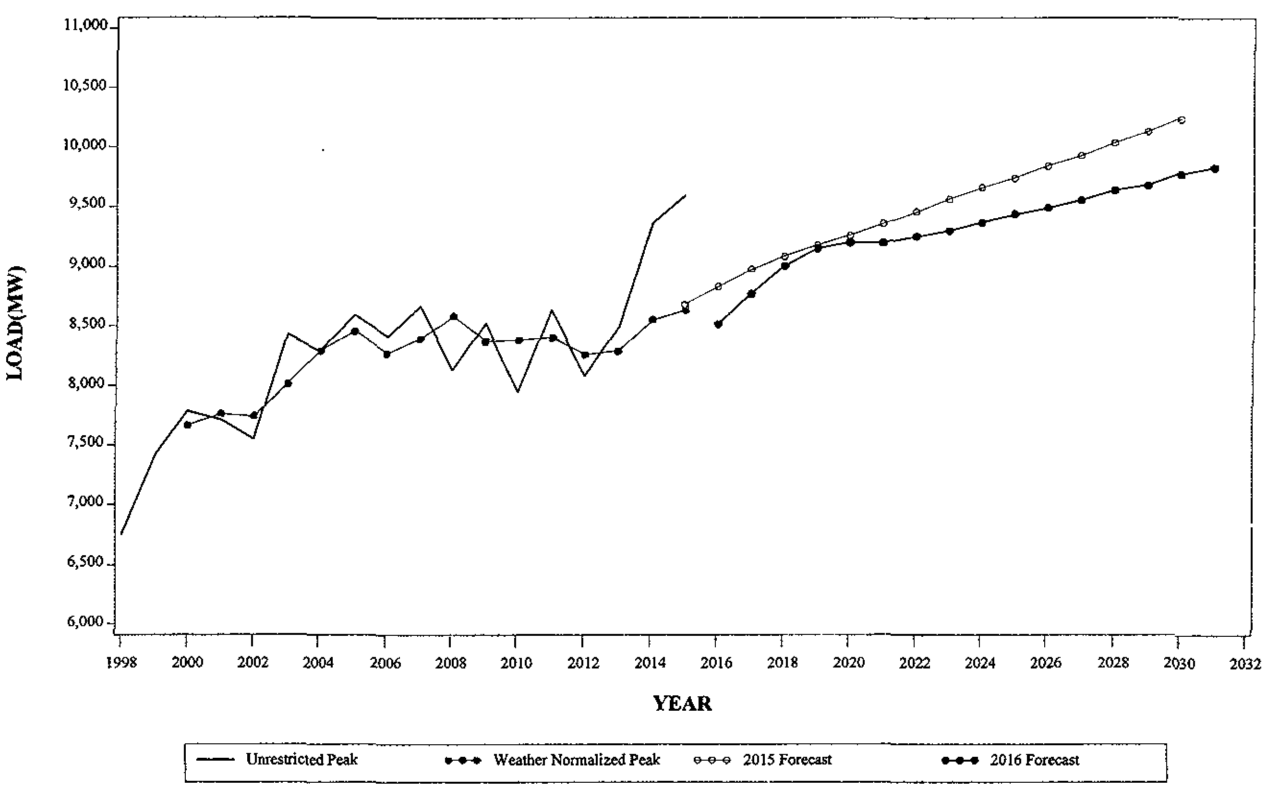
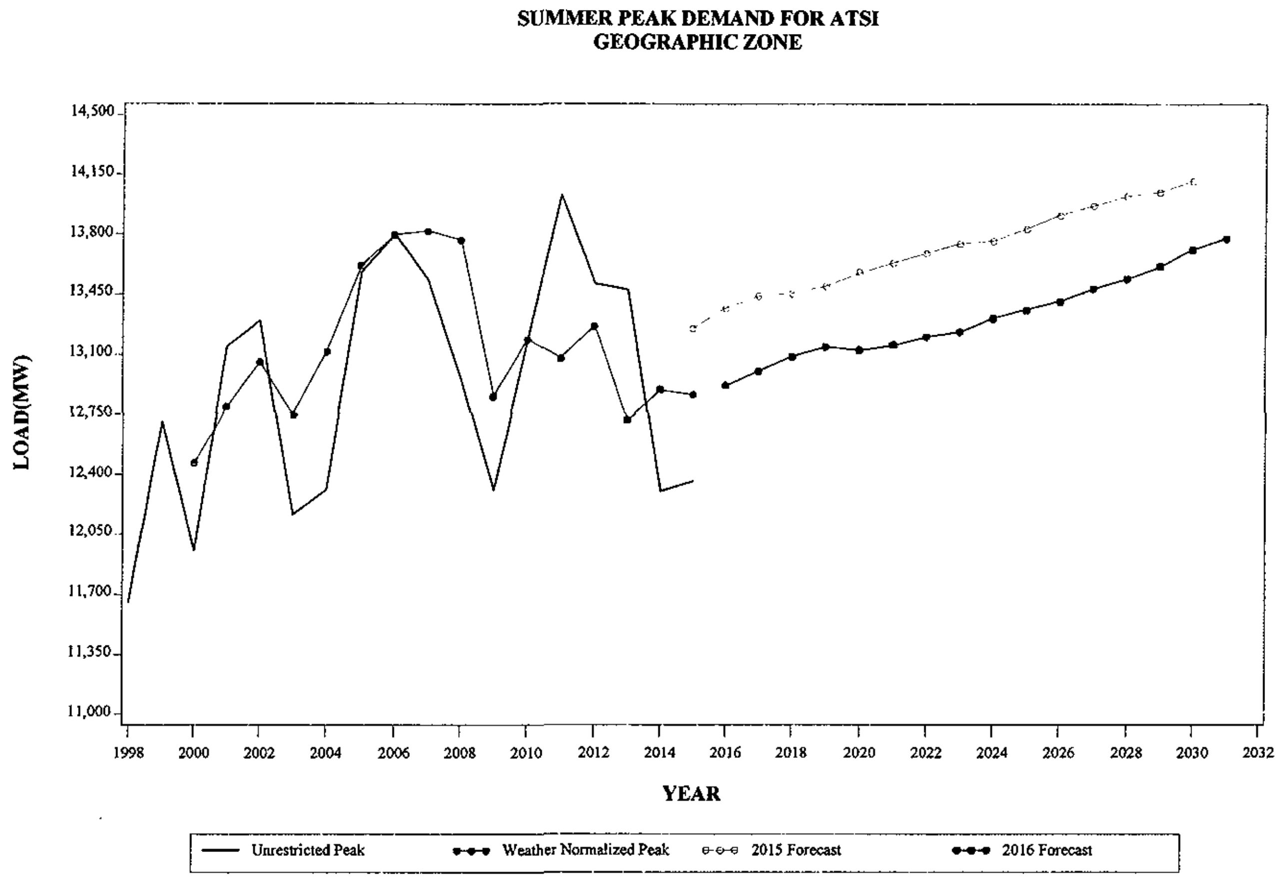
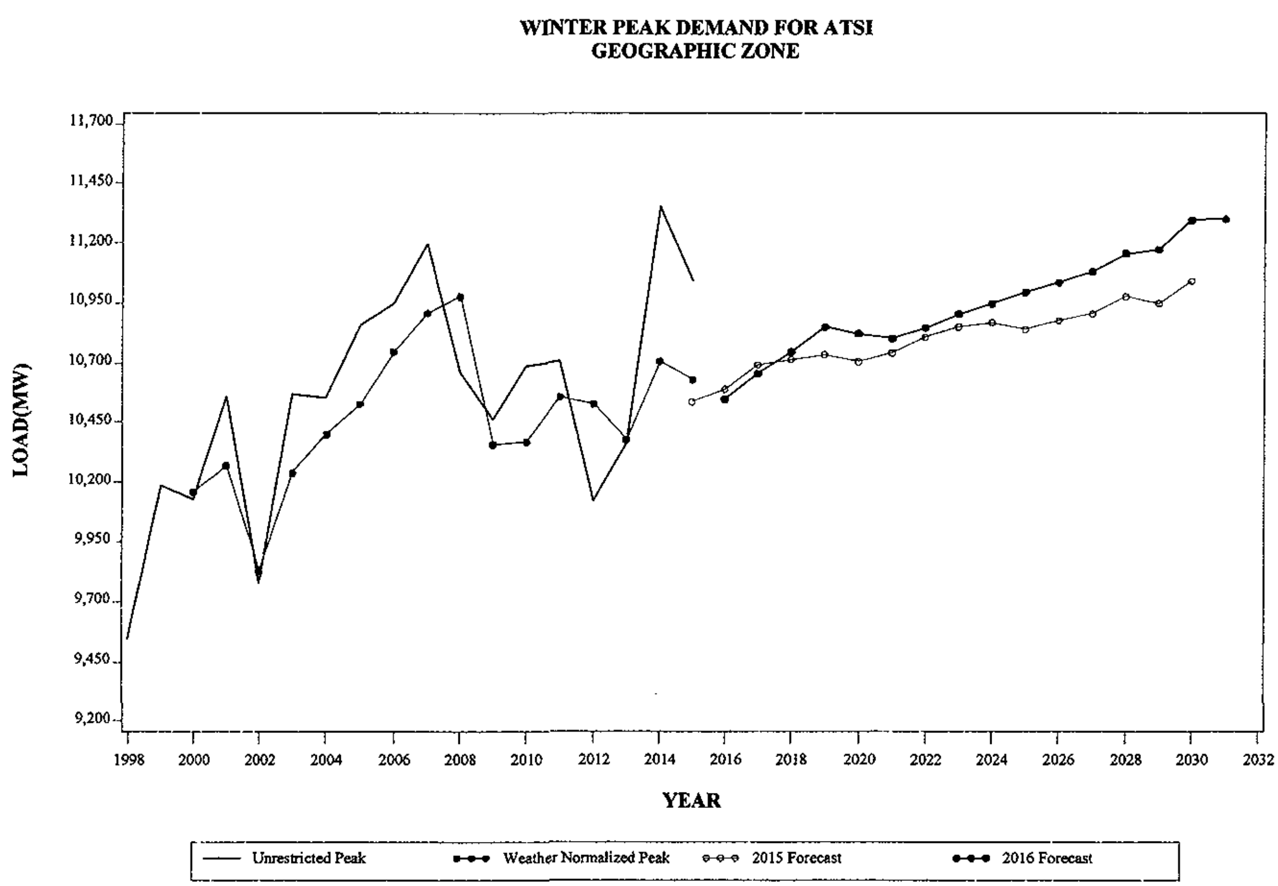
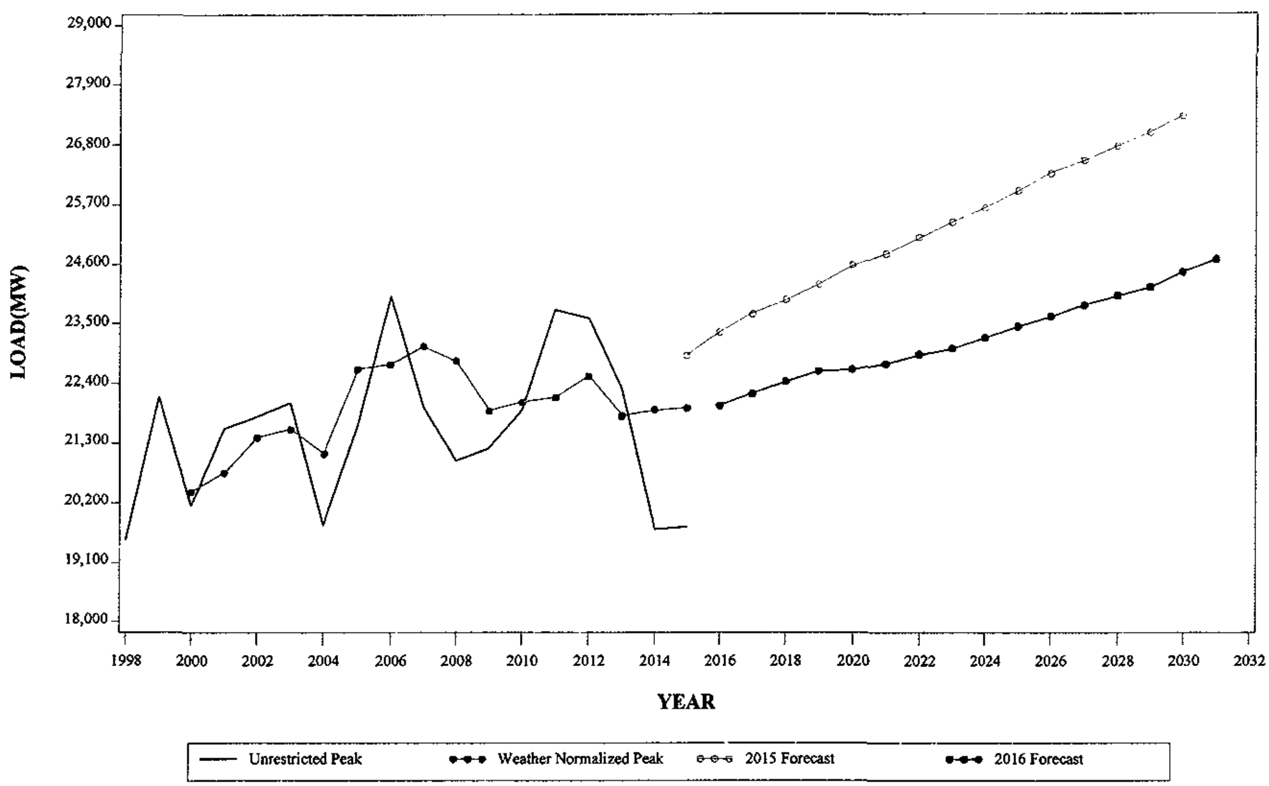


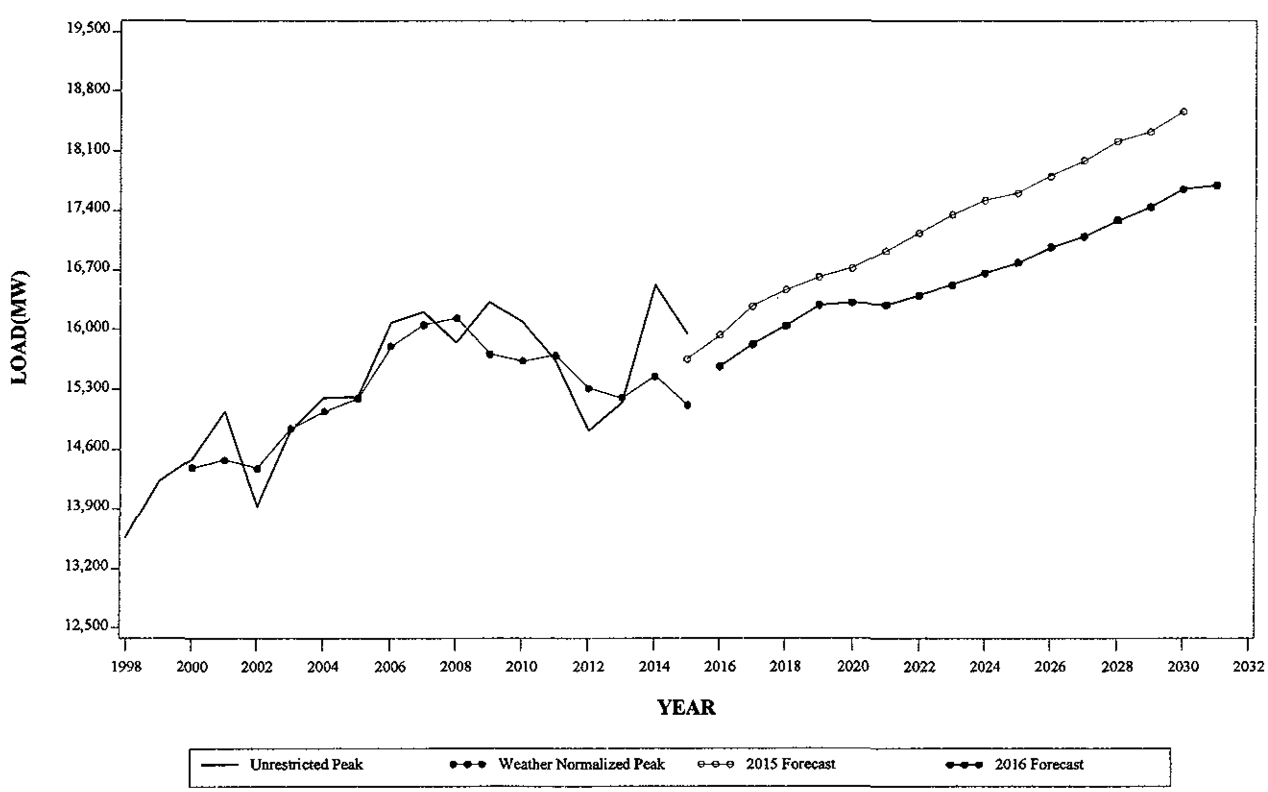

SUMMER PEAK DEMAND FOR ATSI
GEOGRAPHIC ZONE
LOAD(MW)
14,500
14,150
13,800
13,450
13,100
12,750
12,400
12,050
11,700
11,350
11,000
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
YEAR
Unrestricted Peak
Weather Normalized Peak
2015 Forecast
2016 Forecast


WINTER PEAK DEMAND FOR ATSI
GEOGRAPHIC ZONE
LOAD(MW)
11,700
11,450
11,200
10,950
10,700
10,450
10,200
9,950
9,700
9,450
9,200
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
YEAR
Unrestricted Peak
Weather Normalized Peak
2015 Forecast
2016 Forecast

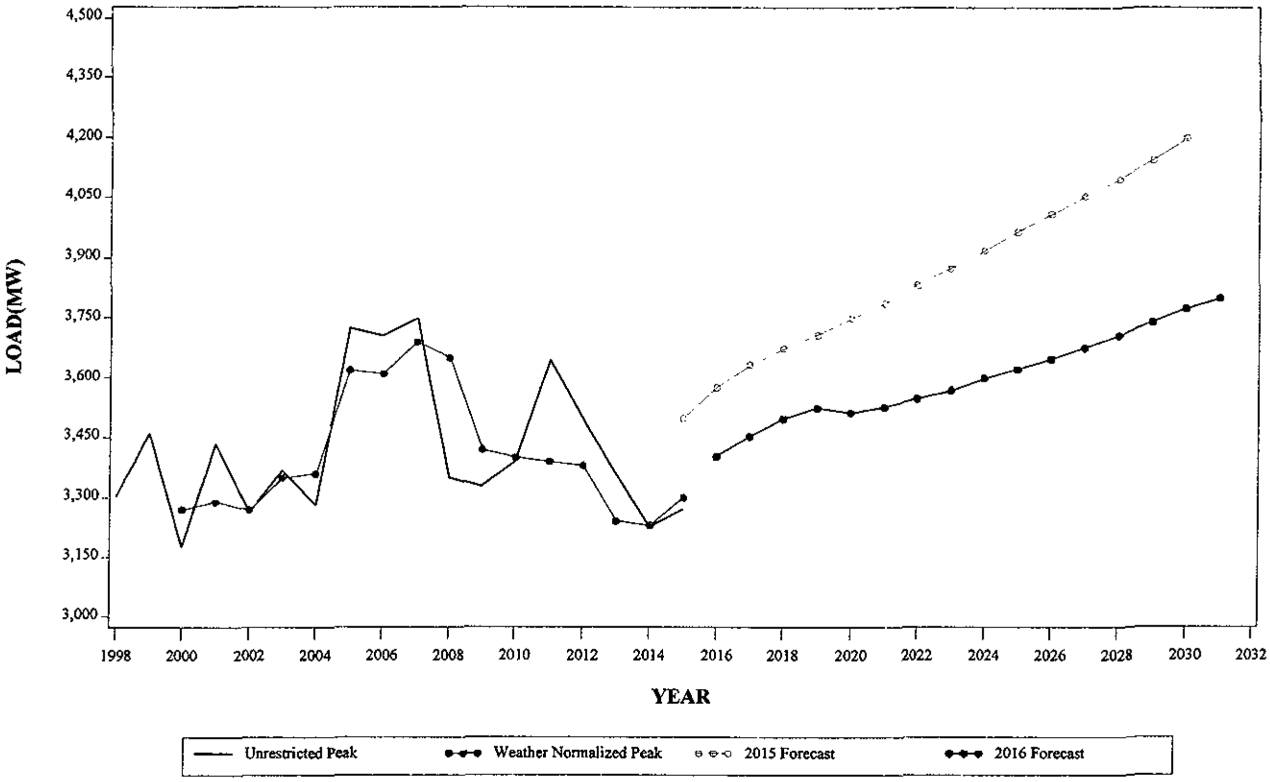
SUMMER PEAK DEMAND FOR COMED GEOGRAPHIC ZONE



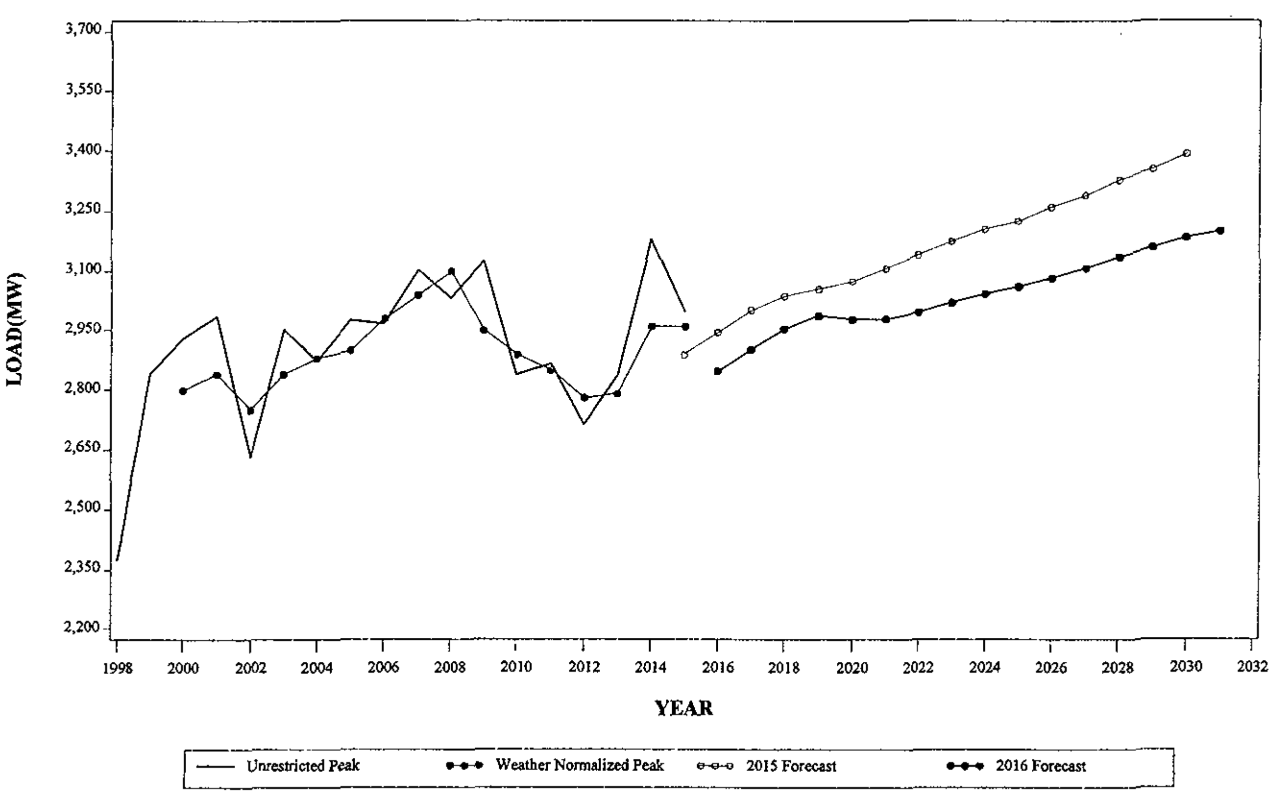
WINTER PEAK DEMAND FOR COMED GEOGRAPHIC ZONE



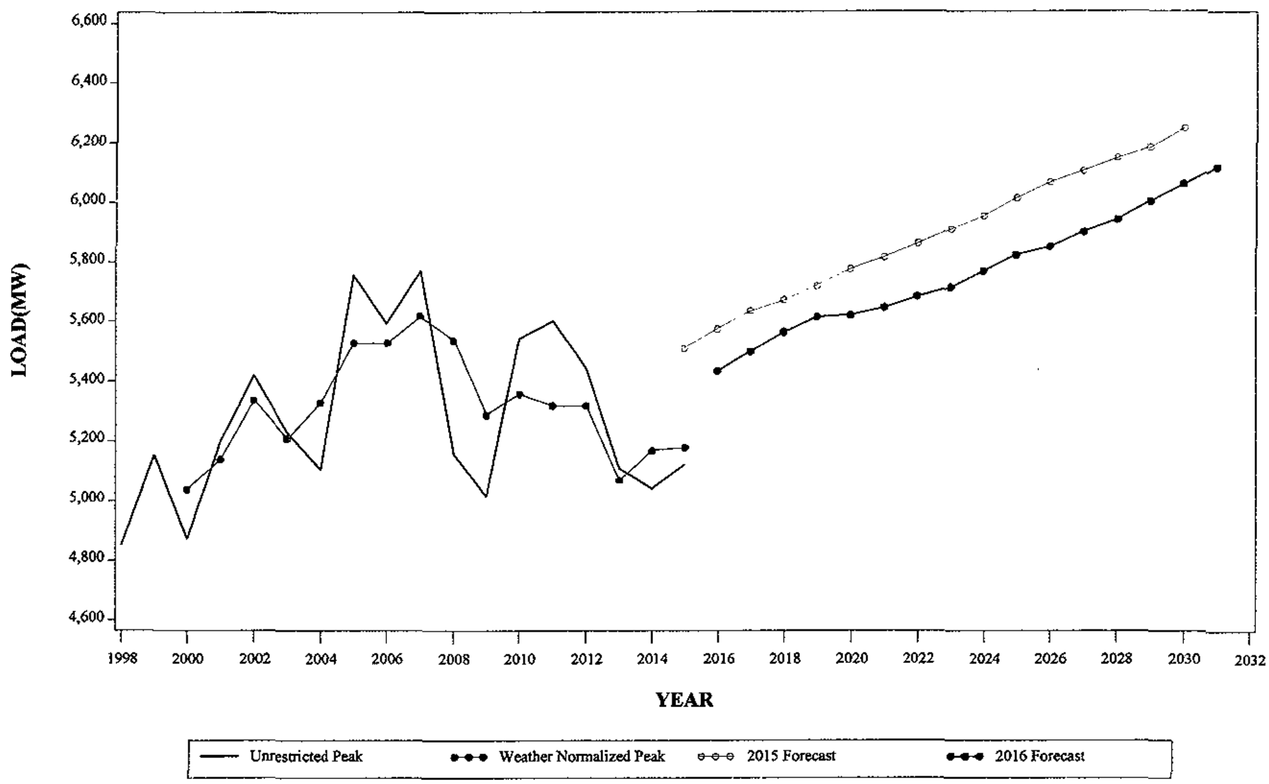
SUMMER PEAK DEMAND FOR DAYTON GEOGRAPHIC ZONE



WINTER PEAK DEMAND FOR DAYTON GEOGRAPHIC ZONE



SUMMER PEAK DEMAND FOR DEOK GEOGRAPHIC ZONE



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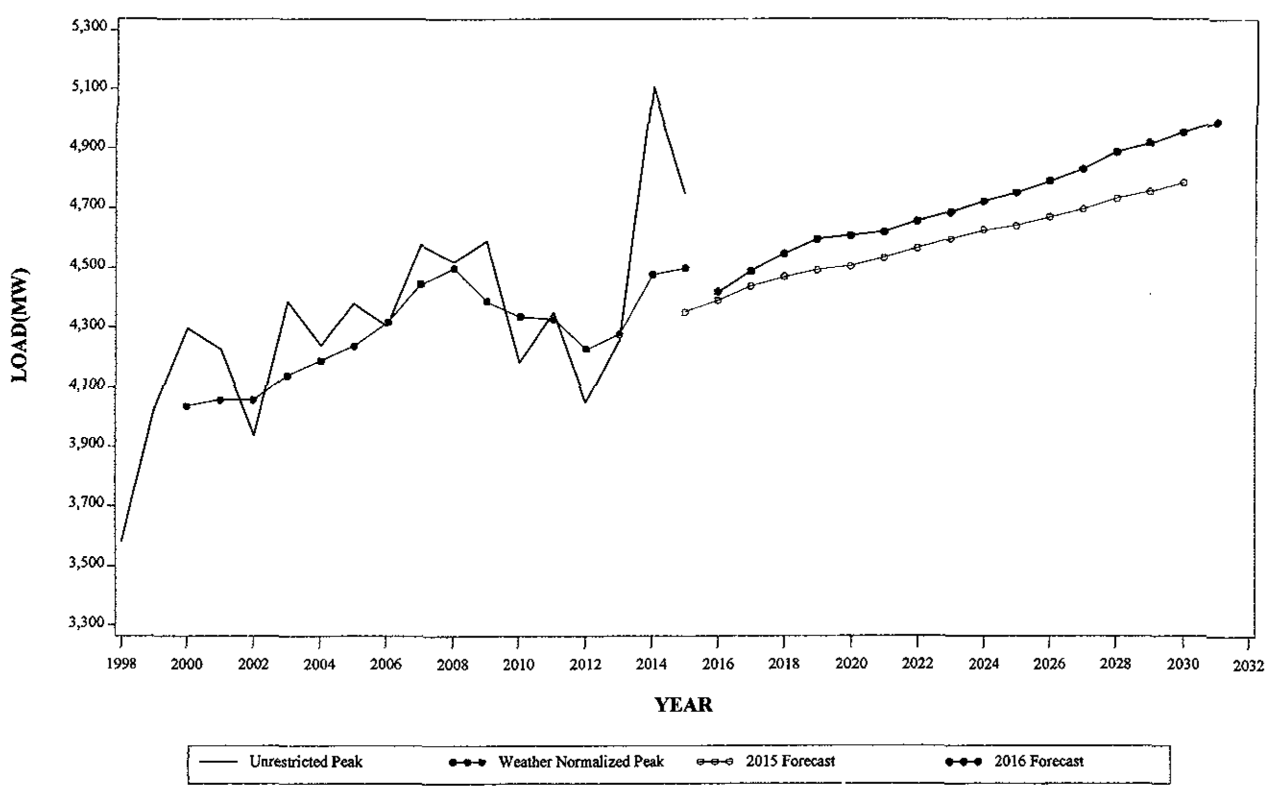
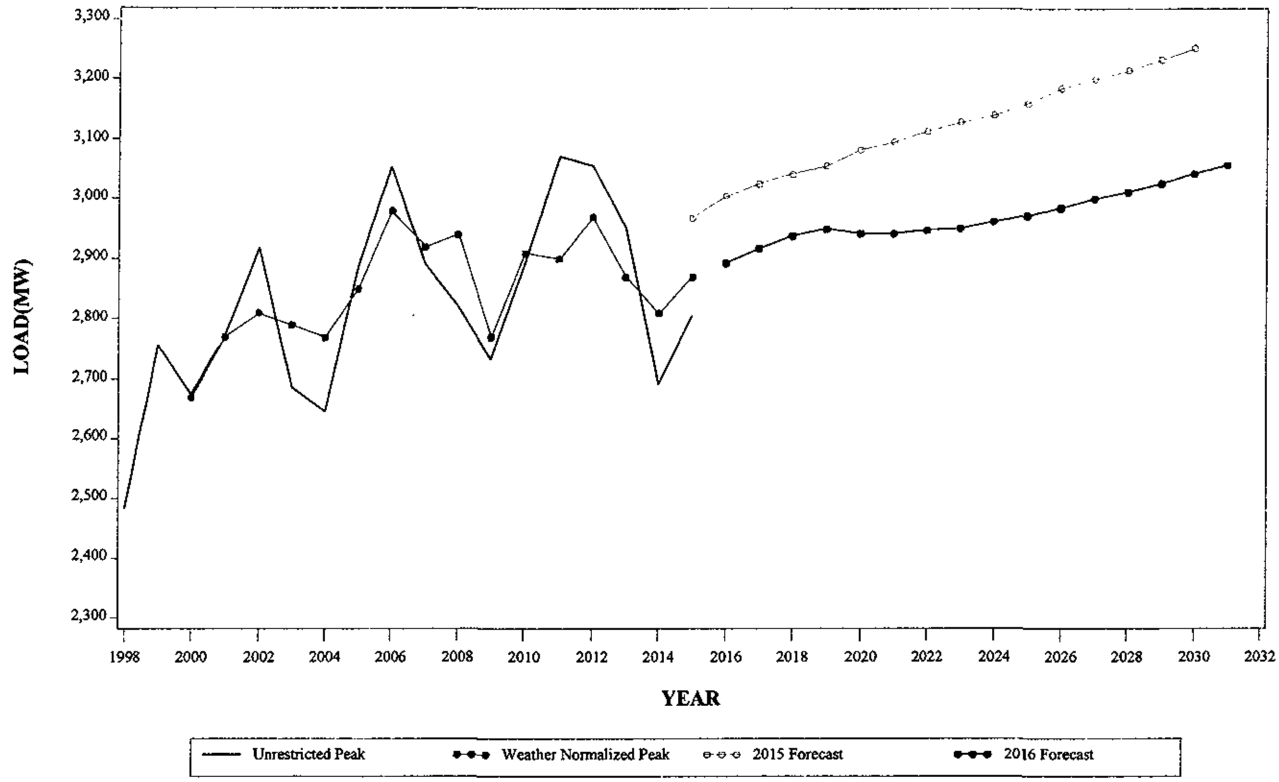
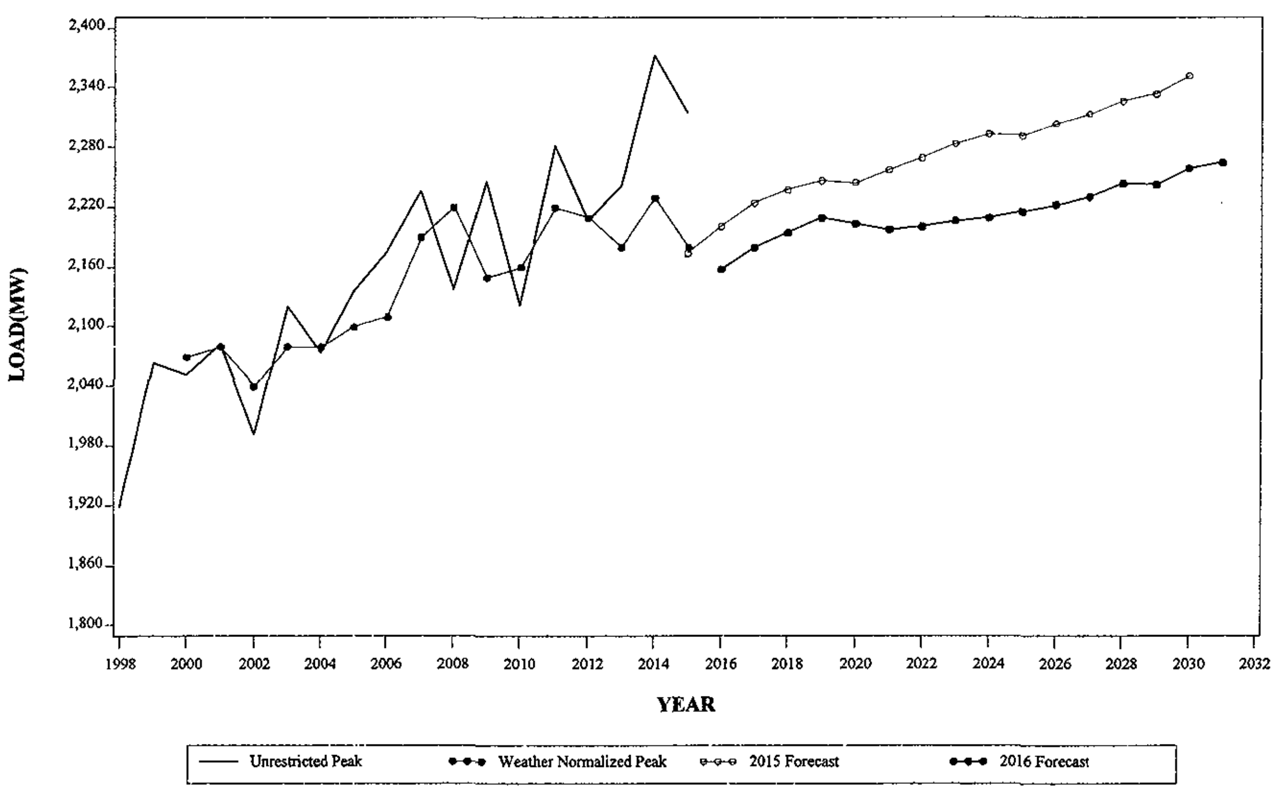


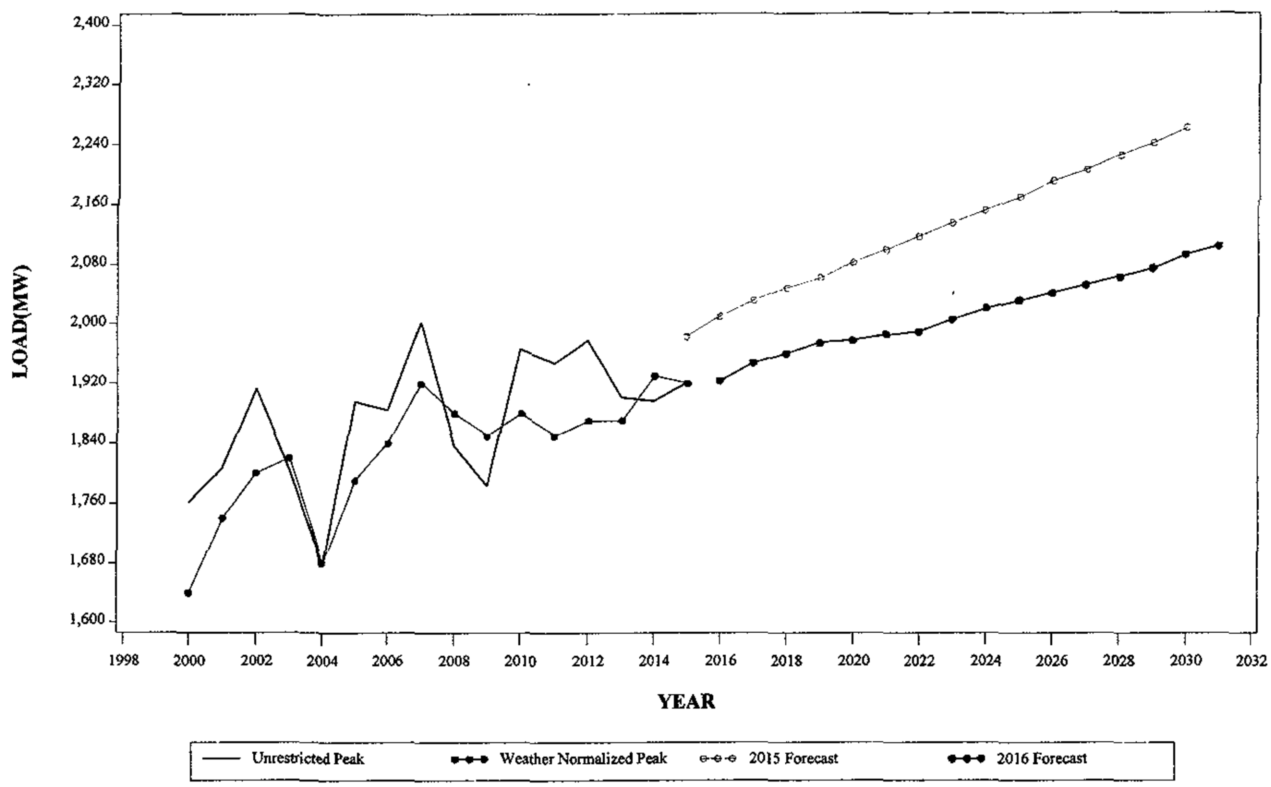
SUMMER PEAK DEMAND FOR DLCO
GEOGRAPHIC ZONE



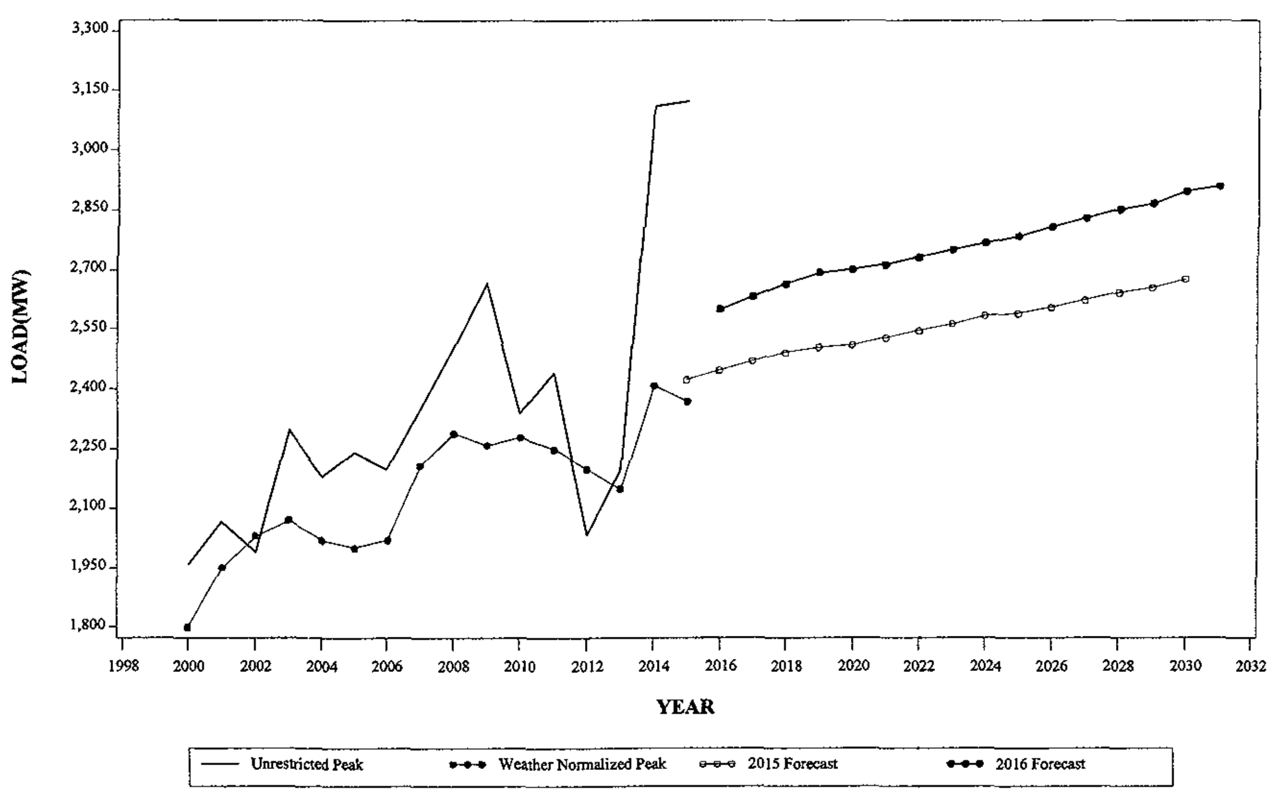
WINTER PEAK DEMAND FOR DLCO
GEOGRAPHIC ZONE



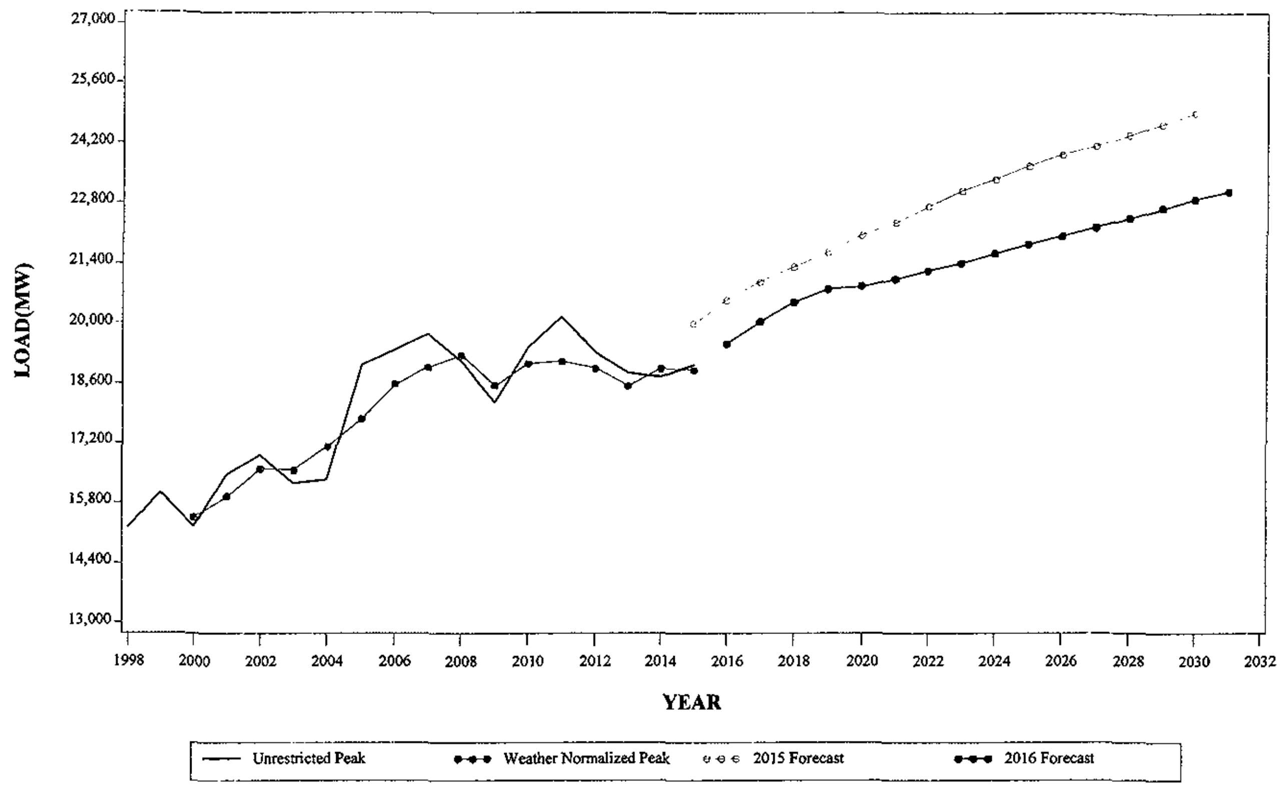
SUMMER PEAK DEMAND FOR EKPC GEOGRAPHIC ZONE



WINTER PEAK DEMAND FOR EKPC GEOGRAPHIC ZONE



SUMMER PEAK DEMAND FOR DOM
GEOGRAPHIC ZONE



WINTER PEAK DEMAND FOR DOM
GEOGRAPHIC ZONE

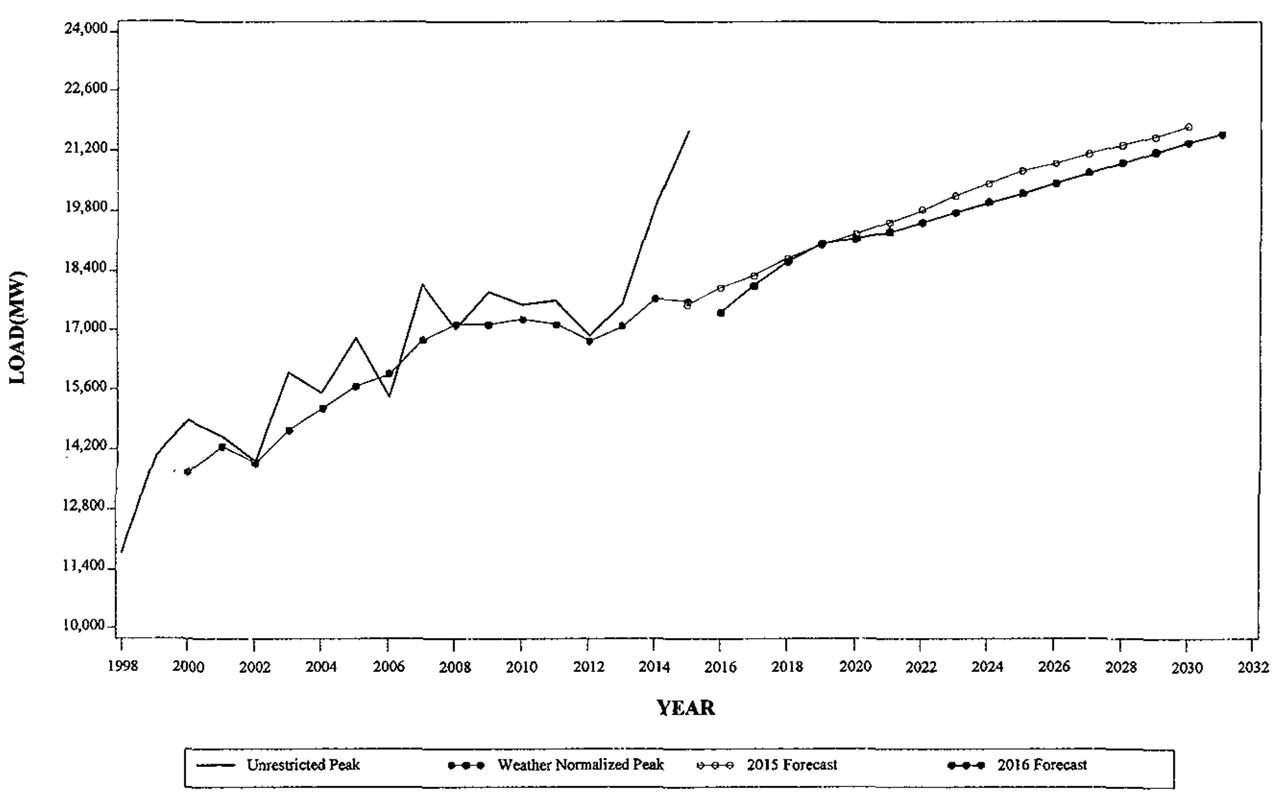


Table A-1

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

INCREASE OR DECREASE OVER PRIOR FORECAST

	2016		2021		2026	
	MW	%	MW	%	MW	%
AE	(178)	-6.6%	(266)	-9.6%	(340)	-12.0%
BGE	(267)	-3.7%	(447)	-6.0%	(602)	-7.7%
DPL	(249)	-5.9%	(354)	-8.0%	(461)	-10.0%
JCPL	(394)	-6.2%	(552)	-8.3%	(758)	-11.0%
METED	(67)	-2.2%	(122)	-3.8%	(179)	-5.3%
PECO	(221)	-2.5%	(359)	-3.9%	(381)	-4.0%
PENLC	(88)	-3.0%	(249)	-7.9%	(388)	-11.7%
PEPCO	(131)	-2.0%	(209)	-3.0%	(252)	-3.6%
PL	(69)	-1.0%	(163)	-2.2%	(254)	-3.3%
PS	(328)	-3.1%	(507)	-4.7%	(750)	-6.8%
RECO	(21)	-4.9%	(26)	-6.0%	(33)	-7.4%
UGI	(12)	-6.0%	(18)	-8.7%	(24)	-11.2%
PJM MID-ATLANTIC	(2,537)	-4.2%	(3,748)	-6.0%	(4,683)	-7.3%
FE-EAST	(630)	-5.2%	(1,000)	-7.8%	(1,369)	-10.3%
PLGRP	(96)	-1.3%	(199)	-2.6%	(283)	-3.5%

Table A-1

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

INCREASE OR DECREASE OVER PRIOR FORECAST

	2016		2021		2026	
	MW	%	MW	%	MW	%
AEP	(806)	-3.4%	(728)	-3.0%	(648)	-2.5%
APS	(55)	-0.6%	(73)	-0.8%	(246)	-2.5%
ATSI	(448)	-3.4%	(478)	-3.5%	(501)	-3.6%
COMED	(1,351)	-5.8%	(2,026)	-8.2%	(2,643)	-10.1%
DAYTON	(172)	-4.8%	(261)	-6.9%	(364)	-9.1%
DEOK	(140)	-2.5%	(168)	-2.9%	(215)	-3.5%
DLCO	(112)	-3.7%	(155)	-5.0%	(202)	-6.3%
EKPC	(86)	-4.3%	(114)	-5.4%	(150)	-6.8%
PJM WESTERN	(3,005)	-3.7%	(3,810)	-4.5%	(4,580)	-5.1%
DOM	(1,020)	-5.0%	(1,313)	-5.9%	(1,904)	-8.0%
PJM RTO	(5,781)	-3.7%	(8,406)	-5.1%	(11,007)	-6.4%

Table A-2

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

INCREASE OR DECREASE OVER PRIOR FORECAST

	15/16		20/21		25/26	
	MW	%	MW	%	MW	%
AE	(64)	-3.8%	(111)	-6.4%	(141)	-8.0%
BGE	96	1.6%	72	1.2%	40	0.6%
DPL	(11)	-0.3%	(21)	-0.6%	(49)	-1.3%
JCPL	(106)	-2.7%	(193)	-4.8%	(304)	-7.2%
METED	(32)	-1.2%	(84)	-3.0%	(150)	-5.1%
PECO	(4)	-0.1%	(144)	-2.1%	(249)	-3.4%
PENLC	(130)	-4.4%	(316)	-10.0%	(480)	-14.5%
PEPCO	19	0.4%	(35)	-0.6%	(117)	-2.0%
PL	(104)	-1.4%	(193)	-2.5%	(308)	-3.9%
PS	62	0.9%	(18)	-0.3%	(135)	-1.9%
RECO	(2)	-0.9%	(2)	-0.8%	(3)	-1.3%
UGI	(10)	-5.0%	(14)	-6.7%	(21)	-9.8%
PJM MID-ATLANTIC	(351)	-0.8%	(1,131)	-2.3%	(1,977)	-4.0%
FE-EAST	(291)	-3.1%	(615)	-6.2%	(934)	-9.0%
PLGRP	(121)	-1.6%	(216)	-2.8%	(335)	-4.2%

Table A-2

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

INCREASE OR DECREASE OVER PRIOR FORECAST

	15/16		20/21		25/26	
	MW	%	MW	%	MW	%
AEP	(432)	-1.9%	(75)	-0.3%	155	0.6%
APS	(311)	-3.5%	(161)	-1.7%	(353)	-3.6%
ATSI	(43)	-0.4%	61	0.6%	159	1.5%
COMED	(362)	-2.3%	(633)	-3.7%	(835)	-4.7%
DAYTON	(98)	-3.3%	(128)	-4.1%	(179)	-5.5%
DEOK	29	0.7%	85	1.9%	120	2.6%
DLCO	(43)	-2.0%	(60)	-2.7%	(81)	-3.5%
EKPC	154	6.3%	184	7.3%	203	7.8%
PJM WESTERN	(1,063)	-1.5%	(765)	-1.1%	(882)	-1.2%
DOM	(586)	-3.3%	(224)	-1.1%	(463)	-2.2%
PJM RTO	(1,478)	-1.1%	(1,616)	-1.2%	(2,698)	-1.9%

Table B-I

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

	METERED 2015	UNRESTRICTED 2015	NORMAL 2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Annual Growth Rate (10 yr)
AE	2,553	2,553	2,580	2,524	2,530	2,534	2,534	2,521	2,507	2,506	2,502	2,503	2,506	2,502	(0.1%)
				-2.2%	0.2%	0.2%	0.0%	-0.5%	-0.6%	-0.0%	-0.2%	0.0%	0.1%	-0.2%	
BGE	6,508	6,508	6,750	6,945	6,989	7,060	7,064	7,079	7,064	7,060	7,078	7,140	7,190	7,220	0.4%
				2.9%	0.6%	1.0%	0.1%	0.2%	-0.2%	-0.1%	0.3%	0.9%	0.7%	0.4%	
DPL	3,822	3,822	3,930	3,991	4,030	4,055	4,068	4,071	4,064	4,071	4,076	4,092	4,121	4,135	0.4%
				1.6%	1.0%	0.6%	0.3%	0.1%	-0.2%	0.2%	0.1%	0.4%	0.7%	0.3%	
JCPL	5,819	5,819	6,010	5,968	6,038	6,096	6,103	6,097	6,091	6,076	6,082	6,100	6,131	6,156	0.3%
				-0.7%	1.2%	1.0%	0.1%	-0.1%	-0.1%	-0.2%	0.1%	0.3%	0.5%	0.4%	
METED	2,791	2,792	2,870	2,940	2,975	3,019	3,051	3,045	3,055	3,068	3,075	3,123	3,147	3,176	0.8%
				2.4%	1.2%	1.5%	1.1%	-0.2%	0.3%	0.4%	0.2%	1.6%	0.8%	0.9%	
PECO	8,095	8,095	8,390	8,547	8,658	8,745	8,797	8,809	8,797	8,842	8,885	8,954	9,012	9,122	0.7%
				1.9%	1.3%	1.0%	0.6%	0.1%	-0.1%	0.5%	0.5%	0.8%	0.6%	1.2%	
PENLC	2,819	2,819	2,940	2,890	2,900	2,904	2,908	2,907	2,899	2,901	2,899	2,903	2,908	2,919	0.1%
				-1.7%	0.3%	0.1%	0.1%	-0.0%	-0.3%	0.1%	-0.1%	0.1%	0.2%	0.4%	
PEPCO	6,268	6,268	6,090	6,563	6,614	6,630	6,669	6,702	6,672	6,680	6,693	6,716	6,750	6,813	0.4%
				7.8%	0.8%	0.2%	0.6%	0.5%	-0.4%	0.1%	0.2%	0.3%	0.5%	0.9%	
PL	6,580	6,580	6,920	7,193	7,270	7,338	7,377	7,362	7,376	7,405	7,424	7,469	7,517	7,560	0.5%
				3.9%	1.1%	0.9%	0.5%	-0.2%	0.2%	0.4%	0.3%	0.6%	0.6%	0.6%	
PS	9,595	9,595	9,910	10,090	10,173	10,234	10,239	10,214	10,191	10,187	10,179	10,186	10,207	10,222	0.1%
				1.8%	0.8%	0.6%	0.0%	-0.2%	-0.2%	-0.0%	-0.1%	0.1%	0.2%	0.1%	
RECO	398	398	405	407	409	411	411	411	409	409	409	409	410	410	0.1%
				0.5%	0.5%	0.5%	0.0%	0.0%	-0.5%	0.0%	0.0%	0.0%	0.2%	0.0%	
UGI	189	189	195	188	190	191	191	190	189	189	189	190	190	190	0.1%
				-3.6%	1.1%	0.5%	0.0%	-0.5%	-0.5%	0.0%	0.0%	0.5%	0.0%	0.0%	
DIVERSITY - MID-ATLANTIC(-)				1,072	1,040	1,023	948	885	1,004	956	876	944	793	872	
PJM MID-ATLANTIC	54,890	54,890	56,495	57,174	57,736	58,194	58,464	58,523	58,310	58,438	58,615	58,841	59,296	59,553	0.4%
				1.2%	1.0%	0.8%	0.5%	0.1%	-0.4%	0.2%	0.3%	0.4%	0.8%	0.4%	
FE-EAST	11,267	11,267	11,670	11,538	11,655	11,762	11,810	11,771	11,765	11,795	11,831	11,882	11,929	11,982	0.4%
				-1.1%	1.0%	0.9%	0.4%	-0.3%	-0.1%	0.3%	0.3%	0.4%	0.4%	0.4%	
PLGRP	6,759	6,759	7,110	7,336	7,417	7,487	7,525	7,513	7,521	7,548	7,576	7,620	7,666	7,714	0.5%
				3.2%	1.1%	0.9%	0.5%	-0.2%	0.1%	0.4%	0.4%	0.6%	0.6%	0.6%	

Notes:
Normal 2015 and all forecast values are non-coincident as estimated by PJM staff.
Normal 2015 and all forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2016).
Summer season indicates peak from June, July, August.

Table B-1 (Continued)

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

	2027	2028	2029	2030	2031	Annual Growth Rate (15 yr)
AE	2,497	2,493	2,489	2,484	2,485	(0.1%)
	-0.2%	-0.2%	-0.2%	-0.2%	0.0%	
BGE	7,231	7,238	7,299	7,321	7,374	0.4%
	0.2%	0.1%	0.8%	0.3%	0.7%	
DPL	4,140	4,155	4,171	4,181	4,200	0.3%
	0.1%	0.4%	0.4%	0.2%	0.5%	
JCPL	6,181	6,174	6,210	6,218	6,255	0.3%
	0.4%	-0.1%	0.6%	0.1%	0.6%	
METED	3,205	3,213	3,259	3,301	3,332	0.8%
	0.9%	0.2%	1.4%	1.3%	0.9%	
PECO	9,161	9,237	9,320	9,404	9,487	0.7%
	0.4%	0.8%	0.9%	0.9%	0.9%	
PENLC	2,919	2,920	2,924	2,933	2,942	0.1%
	0.0%	0.0%	0.1%	0.3%	0.3%	
PEPCO	6,811	6,833	6,847	6,893	6,935	0.4%
	-0.0%	0.3%	0.2%	0.7%	0.6%	
PL	7,619	7,659	7,714	7,769	7,831	0.6%
	0.8%	0.5%	0.7%	0.7%	0.8%	
PS	10,241	10,243	10,253	10,271	10,297	0.1%
	0.2%	0.0%	0.1%	0.2%	0.3%	
RECO	410	410	411	411	412	0.1%
	0.0%	0.0%	0.2%	0.0%	0.2%	
UGI	191	191	192	193	194	0.2%
	0.5%	0.0%	0.5%	0.5%	0.5%	
DIVERSITY - MID-ATLANTIC(-)	1,002	877	913	961	804	
PJM MID-ATLANTIC	59,604	59,889	60,176	60,418	60,940	0.4%
	0.1%	0.5%	0.5%	0.4%	0.9%	
FE-EAST	12,036	12,095	12,164	12,216	12,290	0.4%
	0.5%	0.5%	0.6%	0.4%	0.6%	
PLGRP	7,770	7,816	7,876	7,924	7,986	0.6%
	0.7%	0.6%	0.8%	0.6%	0.8%	

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2016).
Summer season indicates peak from June, July, August.

Table B-1

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

	METERED 2015	UNRESTRICTED 2015	NORMAL 2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Annual Growth Rate (10 yr)
AEP	21,877	21,877	22,490	23,006	23,309	23,584	23,799	23,819	23,943	24,119	24,280	24,517	24,690	24,891	0.8%
				2.3%	1.3%	1.2%	0.9%	0.1%	0.5%	0.7%	0.7%	1.0%	0.7%	0.8%	
APS	8,257	8,257	8,480	8,817	9,014	9,127	9,215	9,248	9,266	9,314	9,350	9,413	9,497	9,554	0.8%
				4.0%	2.2%	1.3%	1.0%	0.4%	0.2%	0.5%	0.4%	0.7%	0.9%	0.6%	
ATSI	12,357	12,357	12,870	12,921	13,004	13,089	13,149	13,129	13,158	13,207	13,236	13,313	13,361	13,413	0.4%
				0.4%	0.6%	0.7%	0.5%	-0.2%	0.2%	0.4%	0.2%	0.6%	0.4%	0.4%	
COMED	19,766	19,768	21,950	22,001	22,216	22,438	22,633	22,659	22,767	22,935	23,045	23,248	23,449	23,633	0.7%
				0.2%	1.0%	1.0%	0.9%	0.1%	0.5%	0.7%	0.5%	0.9%	0.9%	0.8%	
DAYTON	3,269	3,269	3,300	3,403	3,453	3,496	3,524	3,512	3,526	3,548	3,568	3,599	3,622	3,647	0.7%
				3.1%	1.5%	1.2%	0.8%	-0.3%	0.4%	0.6%	0.6%	0.9%	0.6%	0.7%	
DEOK	5,123	5,123	5,180	5,436	5,500	5,566	5,616	5,621	5,648	5,685	5,714	5,771	5,824	5,853	0.7%
				4.9%	1.2%	1.2%	0.9%	0.1%	0.5%	0.7%	0.5%	1.0%	0.9%	0.5%	
DLCO	2,805	2,805	2,870	2,893	2,918	2,938	2,950	2,942	2,942	2,948	2,951	2,963	2,973	2,985	0.3%
				0.8%	0.9%	0.7%	0.4%	-0.3%	0.0%	0.2%	0.1%	0.4%	0.3%	0.4%	
EKPC	1,920	1,920	1,920	1,924	1,947	1,960	1,974	1,977	1,985	1,989	2,006	2,021	2,031	2,041	0.6%
				0.2%	1.2%	0.7%	0.7%	0.2%	0.4%	0.2%	0.9%	0.7%	0.5%	0.5%	
DIVERSITY - WESTERN(-)				1,572	1,589	1,564	1,558	1,559	1,580	1,614	1,493	1,547	1,574	1,574	
PJM WESTERN	74,531	74,579	77,980	78,829	79,772	80,634	81,302	81,348	81,655	82,131	82,657	83,298	83,873	84,443	0.7%
				1.1%	1.2%	1.1%	0.8%	0.1%	0.4%	0.6%	0.6%	0.8%	0.7%	0.7%	
DOM	18,980	19,024	18,920	19,531	20,052	20,499	20,813	20,882	21,054	21,244	21,421	21,640	21,854	22,041	1.2%
				3.2%	2.7%	2.2%	1.5%	0.3%	0.8%	0.9%	0.8%	1.0%	1.0%	0.9%	
DIVERSITY - INTERREGIONAL(-)				3,403	3,411	3,414	3,621	3,866	3,661	3,827	3,718	3,788	4,076	4,146	
PJM RTO	143,447	143,497	150,295	152,131	154,149	155,913	156,958	156,887	157,358	157,986	158,975	159,991	160,947	161,891	0.6%
				1.2%	1.3%	1.1%	0.7%	-0.0%	0.3%	0.4%	0.6%	0.6%	0.6%	0.6%	

Notes:
Normal 2015 and all forecast values are non-coincident as estimated by PJM staff.
Normal 2015 and all forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2016).
Summer season indicates peak from June, July, August.

Table B-1 (Continued)

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

	2027	2028	2029	2030	2031	Annual Growth Rate (15 yr)
AEP	25,113	25,322	25,560	25,828	26,042	0.8%
	0.9%	0.8%	0.9%	1.0%	0.8%	
APS	9,612	9,665	9,734	9,814	9,902	0.8%
	0.6%	0.6%	0.7%	0.8%	0.9%	
ATSI	13,487	13,544	13,618	13,713	13,779	0.4%
	0.6%	0.4%	0.5%	0.7%	0.5%	
COMED	23,840	24,016	24,174	24,460	24,695	0.8%
	0.9%	0.7%	0.7%	1.2%	1.0%	
DAYTON	3,675	3,706	3,738	3,772	3,799	0.7%
	0.8%	0.8%	0.9%	0.9%	0.7%	
DEOK	5,901	5,942	6,003	6,063	6,119	0.8%
	0.8%	0.7%	1.0%	1.0%	0.9%	
DLCO	3,000	3,012	3,026	3,042	3,057	0.4%
	0.5%	0.4%	0.5%	0.5%	0.5%	
EKPC	2,052	2,063	2,075	2,093	2,104	0.6%
	0.5%	0.5%	0.6%	0.9%	0.5%	
DIVERSITY - WESTERN(-)	1,581	1,478	1,415	1,562	1,590	
PJM WESTERN	85,099	85,792	86,513	87,223	87,907	0.7%
	0.8%	0.8%	0.8%	0.8%	0.8%	
DOM	22,256	22,466	22,695	22,904	23,085	1.1%
	1.0%	0.9%	1.0%	0.9%	0.8%	
DIVERSITY - INTERREGIONAL(-)	3,971	4,002	3,992	4,133	4,463	
PJM RTO	162,988	164,145	165,392	166,412	167,469	0.6%
	0.7%	0.7%	0.8%	0.6%	0.6%	

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2016).
Summer season indicates peak from June, July, August.

Table B-2

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

	METERED 14/15	UNRESTRICTED 14/15	NORMAL 14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	Annual Growth Rate (10 yr)
AE	1,705	1,705	1,610	1,626	1,632	1,640	1,647	1,634	1,620	1,620	1,621	1,623	1,623	1,624	(0.0%)
				1.0%	0.4%	0.5%	0.4%	-0.8%	-0.9%	0.0%	0.1%	0.1%	0.0%	0.1%	
BGE	6,712	6,712	5,760	5,941	5,994	6,044	6,078	6,080	6,077	6,098	6,118	6,142	6,168	6,199	0.4%
				3.1%	0.9%	0.8%	0.6%	0.0%	-0.0%	0.3%	0.3%	0.4%	0.4%	0.5%	
DPL	4,114	4,114	3,480	3,413	3,461	3,507	3,538	3,545	3,548	3,560	3,577	3,598	3,623	3,646	0.7%
				-1.9%	1.4%	1.3%	0.9%	0.2%	0.1%	0.3%	0.5%	0.6%	0.7%	0.6%	
JCPL	3,805	3,805	3,730	3,766	3,822	3,880	3,914	3,881	3,853	3,857	3,859	3,874	3,885	3,892	0.3%
				1.0%	1.5%	1.5%	0.9%	-0.8%	-0.7%	0.1%	0.1%	0.4%	0.3%	0.2%	
METED	2,799	2,799	2,610	2,593	2,637	2,679	2,711	2,704	2,700	2,711	2,730	2,748	2,767	2,784	0.7%
				-0.7%	1.7%	1.6%	1.2%	-0.3%	-0.1%	0.4%	0.7%	0.7%	0.7%	0.6%	
PECO	7,034	7,034	6,620	6,654	6,770	6,858	6,909	6,891	6,862	6,899	6,929	6,964	6,996	7,030	0.6%
				0.5%	1.7%	1.3%	0.7%	-0.3%	-0.4%	0.5%	0.4%	0.5%	0.5%	0.5%	
PENLC	3,025	3,025	2,860	2,814	2,828	2,836	2,849	2,841	2,829	2,830	2,833	2,835	2,834	2,834	0.1%
				-1.6%	0.5%	0.3%	0.5%	-0.3%	-0.4%	0.0%	0.1%	0.1%	-0.0%	0.0%	
PEPCO	6,066	6,066	5,370	5,386	5,455	5,514	5,555	5,572	5,564	5,593	5,617	5,643	5,668	5,684	0.5%
				0.3%	1.3%	1.1%	0.7%	0.3%	-0.1%	0.5%	0.4%	0.5%	0.4%	0.3%	
PL	7,845	7,845	7,140	7,210	7,297	7,385	7,437	7,427	7,404	7,417	7,438	7,475	7,511	7,541	0.4%
				1.0%	1.2%	1.2%	0.7%	-0.1%	-0.3%	0.2%	0.3%	0.5%	0.5%	0.4%	
PS	6,697	6,697	6,570	6,712	6,801	6,868	6,923	6,890	6,847	6,842	6,856	6,871	6,886	6,904	0.3%
				2.2%	1.3%	1.0%	0.8%	-0.5%	-0.6%	-0.1%	0.2%	0.2%	0.2%	0.3%	
RECO	232	232	220	232	234	235	237	235	234	235	235	235	234	234	0.1%
				5.5%	0.9%	0.4%	0.9%	-0.8%	-0.4%	0.4%	0.0%	0.0%	-0.4%	0.0%	
UGI	211	211	200	192	194	196	197	195	194	193	193	193	193	193	0.1%
				-4.0%	1.0%	1.0%	0.5%	-1.0%	-0.5%	-0.5%	0.0%	0.0%	0.0%	0.0%	
DIVERSITY - MID-ATLANTIC(-)				717	621	632	738	798	733	670	659	644	761	745	
PJM MID-ATLANTIC	49,369	49,369	45,485	45,822	46,504	47,010	47,257	47,097	46,999	47,185	47,347	47,557	47,627	47,820	0.4%
				0.7%	1.5%	1.1%	0.5%	-0.3%	-0.2%	0.4%	0.3%	0.4%	0.1%	0.4%	
FE-EAST	9,505	9,505	9,140	9,095	9,229	9,335	9,406	9,336	9,305	9,323	9,358	9,403	9,411	9,442	0.4%
				-0.5%	1.5%	1.1%	0.8%	-0.7%	-0.3%	0.2%	0.4%	0.5%	0.1%	0.3%	
PLGRP	8,055	8,055	7,335	7,387	7,476	7,566	7,610	7,584	7,578	7,595	7,614	7,653	7,680	7,711	0.4%
				0.7%	1.2%	1.2%	0.6%	-0.3%	-0.1%	0.2%	0.3%	0.5%	0.4%	0.4%	

Notes:
Normal 14/15 and all forecast values are non-coincident as estimated by PJM staff.
Normal 14/15 and all forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2015/16).
Winter season indicates peak from December, January, February.

Table B-2 (Continued)

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

	26/27	27/28	28/29	29/30	30/31	Annual Growth Rate (15 yr)
AE	1,627	1,636	1,639	1,648	1,644	0.1%
	0.2%	0.6%	0.2%	0.5%	-0.2%	
BGE	6,226	6,261	6,292	6,317	6,345	0.4%
	0.4%	0.6%	0.5%	0.4%	0.4%	
DPL	3,669	3,694	3,718	3,742	3,766	0.7%
	0.6%	0.7%	0.6%	0.6%	0.6%	
JCPL	3,913	3,945	3,967	3,995	4,006	0.4%
	0.5%	0.8%	0.6%	0.7%	0.3%	
METED	2,807	2,830	2,855	2,879	2,898	0.7%
	0.8%	0.8%	0.9%	0.8%	0.7%	
PECO	7,076	7,130	7,180	7,221	7,262	0.6%
	0.7%	0.8%	0.7%	0.6%	0.6%	
PENLC	2,836	2,842	2,841	2,852	2,847	0.1%
	0.1%	0.2%	-0.0%	0.4%	-0.2%	
PEPCO	5,711	5,768	5,781	5,836	5,868	0.6%
	0.5%	1.0%	0.2%	1.0%	0.5%	
PL	7,582	7,625	7,666	7,702	7,745	0.5%
	0.5%	0.6%	0.5%	0.5%	0.6%	
PS	6,921	6,955	6,981	7,028	7,035	0.3%
	0.2%	0.5%	0.4%	0.7%	0.1%	
RECO	235	237	236	238	236	0.1%
	0.4%	0.9%	-0.4%	0.8%	-0.8%	
UGI	193	194	194	195	194	0.1%
	0.0%	0.5%	0.0%	0.5%	-0.5%	
DIVERSITY - MID-ATLANTIC(-)	722	718	669	699	749	
PJM MID-ATLANTIC	48,074	48,399	48,681	48,954	49,097	0.5%
	0.5%	0.7%	0.6%	0.6%	0.3%	
FE-EAST	9,485	9,544	9,603	9,669	9,684	0.4%
	0.5%	0.6%	0.6%	0.7%	0.2%	
PLGRP	7,752	7,796	7,840	7,873	7,919	0.5%
	0.5%	0.6%	0.6%	0.4%	0.6%	

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2015/16).
Winter season indicates peak from December, January, February.

Table B-2

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

	METERED 14/15	UNRESTRICTED 14/15	NORMAL 14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	Annual Growth Rate (10 yr)
AEP	24,739	24,739	21,990	22,506	22,889	23,295	23,615	23,697	23,764	23,948	24,127	24,356	24,565	24,783	1.0%
				2.3%	1.7%	1.8%	1.4%	0.3%	0.3%	0.8%	0.7%	0.9%	0.9%	0.9%	
APS	9,594	9,594	8,640	8,526	8,778	9,009	9,149	9,200	9,201	9,256	9,306	9,373	9,442	9,494	1.1%
				-1.3%	3.0%	2.6%	1.6%	0.6%	0.0%	0.6%	0.5%	0.7%	0.7%	0.6%	
ATSI	11,041	11,041	10,630	10,549	10,657	10,747	10,851	10,823	10,806	10,848	10,906	10,949	10,995	11,038	0.5%
				-0.8%	1.0%	0.8%	1.0%	-0.3%	-0.2%	0.4%	0.5%	0.4%	0.4%	0.4%	
COMED	15,951	15,951	15,120	15,579	15,832	16,051	16,296	16,325	16,297	16,403	16,532	16,669	16,788	16,974	0.9%
				3.0%	1.6%	1.4%	1.5%	0.2%	-0.2%	0.7%	0.8%	0.8%	0.7%	1.1%	
DAYTON	2,999	2,999	2,960	2,848	2,901	2,955	2,987	2,979	2,980	2,997	3,021	3,044	3,062	3,083	0.8%
				-3.8%	1.9%	1.9%	1.1%	-0.3%	0.0%	0.6%	0.8%	0.8%	0.6%	0.7%	
DEOK	4,750	4,750	4,500	4,422	4,489	4,549	4,597	4,609	4,620	4,658	4,688	4,723	4,754	4,792	0.8%
				-1.7%	1.5%	1.3%	1.1%	0.3%	0.2%	0.8%	0.6%	0.7%	0.7%	0.8%	
DLCO	2,315	2,315	2,180	2,158	2,180	2,195	2,210	2,204	2,198	2,201	2,207	2,210	2,216	2,223	0.3%
				-1.0%	1.0%	0.7%	0.7%	-0.3%	-0.3%	0.1%	0.3%	0.1%	0.3%	0.3%	
EKPC	3,123	3,123	2,370	2,602	2,634	2,665	2,694	2,702	2,714	2,732	2,752	2,769	2,786	2,809	0.8%
				9.8%	1.2%	1.2%	1.1%	0.3%	0.4%	0.7%	0.7%	0.6%	0.6%	0.8%	
DIVERSITY - WESTERN(-)				1,373	1,370	1,417	1,658	1,784	1,602	1,497	1,565	1,553	1,551	1,676	
PJM WESTERN	71,834	71,834	66,940	67,817	68,990	70,049	70,741	70,755	70,978	71,546	71,974	72,540	73,057	73,520	0.8%
				1.3%	1.7%	1.5%	1.0%	0.0%	0.3%	0.8%	0.6%	0.8%	0.7%	0.6%	
DOM	21,651	21,651	17,690	17,431	18,063	18,622	19,048	19,165	19,322	19,547	19,774	20,011	20,212	20,460	1.6%
				-1.5%	3.6%	3.1%	2.3%	0.6%	0.8%	1.2%	1.2%	1.2%	1.0%	1.2%	
DIVERSITY - INTERREGIONAL(-)				827	1,075	1,036	967	995	897	1,015	1,085	918	934	888	
PJM RTO	142,762	142,762	128,270	130,243	132,482	134,645	136,079	136,022	136,402	137,263	138,010	139,190	139,962	140,912	0.8%
				1.5%	1.7%	1.6%	1.1%	-0.0%	0.3%	0.6%	0.5%	0.9%	0.6%	0.7%	

Notes:
Normal 14/15 and all forecast values are non-coincident as estimated by PJM staff.
Normal 14/15 and all forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2015/16).
Winter season indicates peak from December, January, February.

Table B-2 (Continued)

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

	26/27	27/28	28/29	29/30	30/31	Annual Growth Rate (15 yr)
AEP	25,013	25,283	25,526	25,825	25,993	1.0%
	0.9%	1.1%	1.0%	1.2%	0.7%	
APS	9,557	9,642	9,680	9,783	9,839	1.0%
	0.7%	0.9%	0.4%	1.1%	0.6%	
ATSI	11,082	11,157	11,176	11,298	11,301	0.5%
	0.4%	0.7%	0.2%	1.1%	0.0%	
COMED	17,101	17,291	17,446	17,660	17,698	0.9%
	0.7%	1.1%	0.9%	1.2%	0.2%	
DAYTON	3,108	3,136	3,160	3,185	3,201	0.8%
	0.8%	0.9%	0.8%	0.8%	0.5%	
DEOK	4,832	4,888	4,919	4,957	4,992	0.8%
	0.8%	1.2%	0.6%	0.8%	0.7%	
DLCO	2,231	2,244	2,243	2,259	2,265	0.3%
	0.4%	0.6%	-0.0%	0.7%	0.3%	
EKPC	2,831	2,853	2,869	2,899	2,912	0.8%
	0.8%	0.8%	0.6%	1.0%	0.4%	
DIVERSITY - WESTERN(-)	1,622	1,667	1,614	1,828	1,678	
PJM WESTERN	74,133	74,827	75,405	76,038	76,523	0.8%
	0.8%	0.9%	0.8%	0.8%	0.6%	
DOM	20,698	20,943	21,188	21,411	21,608	1.4%
	1.2%	1.2%	1.2%	1.1%	0.9%	
DIVERSITY - INTERREGIONAL(-)	918	1,020	1,357	1,100	1,003	
PJM RTO	141,987	143,149	143,917	145,303	146,225	0.8%
	0.8%	0.8%	0.5%	1.0%	0.6%	

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2015/16).
Winter season indicates peak from December, January, February.

Table B-3

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

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
AE	1,699	1,711	1,717	1,720	1,694	1,690	1,691	1,694	1,696	1,687	1,686	1,685	1,688	1,685	1,677	1,666
BGE	5,523	5,565	5,606	5,628	5,590	5,608	5,648	5,664	5,689	5,697	5,734	5,765	5,783	5,816	5,826	5,843
DPL	3,018	3,068	3,098	3,110	3,105	3,114	3,117	3,132	3,145	3,158	3,182	3,199	3,209	3,225	3,228	3,229
JCPL	4,142	4,258	4,325	4,361	4,252	4,228	4,273	4,310	4,347	4,328	4,310	4,322	4,387	4,418	4,428	4,434
METED	2,430	2,476	2,512	2,521	2,504	2,514	2,548	2,570	2,577	2,595	2,615	2,641	2,678	2,703	2,719	2,736
PECO	6,667	6,779	6,870	6,937	6,828	6,842	6,956	7,003	7,063	7,040	7,086	7,148	7,288	7,362	7,413	7,407
PENLC	2,576	2,594	2,598	2,598	2,586	2,585	2,581	2,583	2,568	2,563	2,577	2,581	2,581	2,578	2,574	2,574
PEPCO	5,254	5,328	5,389	5,425	5,357	5,365	5,399	5,444	5,493	5,477	5,490	5,516	5,583	5,641	5,663	5,648
PL	6,377	6,481	6,547	6,581	6,549	6,578	6,596	6,629	6,618	6,638	6,712	6,769	6,798	6,820	6,856	6,890
PS	7,635	7,777	7,852	7,879	7,747	7,738	7,786	7,822	7,840	7,830	7,801	7,818	7,890	7,919	7,925	7,919
RECO	296	298	300	301	299	299	299	299	300	299	299	300	300	301	300	300
UGI	167	170	171	171	169	169	169	169	168	168	169	169	170	170	169	169
DIVERSITY - MID-ATLANTIC(-)	2,366	2,200	2,199	2,329	2,747	3,047	2,486	2,201	2,239	2,359	2,816	3,073	2,135	2,131	2,179	2,339
PJM MID-ATLANTIC	43,418	44,305	44,786	44,903	43,933	43,683	44,577	45,118	45,265	45,121	44,845	44,840	46,220	46,507	46,599	46,476
FE-EAST	8,691	8,861	8,963	8,977	8,793	8,787	8,915	9,012	9,023	9,024	8,958	9,020	9,225	9,286	9,292	9,318
PLGRP	6,423	6,499	6,578	6,609	6,574	6,581	6,621	6,643	6,656	6,675	6,710	6,765	6,806	6,857	6,886	6,923

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.
Spring season indicates peak from March, April, May.

Table B-3

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

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
AEP	20,452	20,806	21,200	21,421	21,406	21,701	21,782	21,924	22,077	22,259	22,578	22,798	22,936	23,126	23,321	23,491
APS	7,765	8,012	8,151	8,251	8,242	8,323	8,344	8,419	8,437	8,503	8,604	8,673	8,719	8,757	8,814	8,863
ATSI	10,409	10,499	10,597	10,702	10,459	10,485	10,700	10,745	10,858	10,717	10,761	10,791	11,031	11,119	11,214	11,076
COMED	16,703	16,948	17,183	17,380	17,255	17,329	17,578	17,722	17,916	18,023	18,214	18,319	18,591	18,801	18,961	19,093
DAYTON	2,750	2,797	2,844	2,877	2,844	2,855	2,896	2,919	2,945	2,960	2,979	3,003	3,051	3,083	3,102	3,120
DEOK	4,433	4,487	4,562	4,616	4,553	4,574	4,654	4,683	4,754	4,757	4,771	4,812	4,895	4,963	5,002	5,016
DLCO	2,340	2,359	2,381	2,396	2,381	2,384	2,391	2,397	2,410	2,412	2,424	2,436	2,453	2,467	2,477	2,480
EKPC	2,057	2,090	2,112	2,126	2,132	2,166	2,171	2,189	2,190	2,208	2,241	2,258	2,262	2,271	2,287	2,303
DIVERSITY - WESTERN(-)	4,303	4,393	4,452	4,656	4,899	5,168	4,738	4,765	4,854	5,137	5,419	5,374	5,130	5,086	5,258	5,231
PJM WESTERN	62,606	63,605	64,578	65,113	64,373	64,649	65,778	66,233	66,733	66,702	67,153	67,716	68,808	69,501	69,920	70,211
DOM	17,013	17,508	18,223	18,589	18,621	18,735	18,810	18,954	19,385	19,510	19,716	19,897	19,959	20,286	20,470	20,610
DIVERSITY - INTERREGIONAL(-)	3,519	3,973	4,015	4,599	4,581	4,467	3,859	4,189	4,481	4,479	4,701	4,541	4,343	4,411	4,549	4,556
PJM RTO	119,518	121,445	123,572	124,006	122,346	122,600	125,306	126,116	126,902	126,854	127,013	127,912	130,644	131,883	132,440	132,741

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.
Spring season indicates peak from March, April, May.

Table B-4

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

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
AE	1,946	1,956	1,960	1,966	1,952	1,949	1,939	1,940	1,947	1,951	1,952	1,954	1,952	1,955	1,958	1,964
BGE	5,848	5,870	5,892	5,958	5,948	5,961	5,963	5,973	6,026	6,060	6,086	6,115	6,123	6,155	6,202	6,236
DPL	3,263	3,310	3,342	3,373	3,360	3,365	3,361	3,382	3,418	3,436	3,451	3,464	3,479	3,511	3,535	3,547
JCPL	4,541	4,607	4,650	4,683	4,653	4,647	4,637	4,652	4,682	4,708	4,728	4,746	4,758	4,794	4,822	4,858
METED	2,490	2,526	2,557	2,593	2,590	2,600	2,605	2,618	2,653	2,688	2,709	2,732	2,740	2,774	2,813	2,849
PECO	7,151	7,249	7,321	7,416	7,387	7,413	7,426	7,464	7,551	7,605	7,659	7,718	7,762	7,844	7,930	7,996
PENLC	2,581	2,587	2,585	2,594	2,584	2,585	2,586	2,584	2,586	2,593	2,594	2,599	2,599	2,599	2,602	2,618
PEPCO	5,583	5,618	5,636	5,691	5,712	5,725	5,718	5,718	5,753	5,807	5,838	5,869	5,863	5,883	5,936	5,989
PL	6,194	6,290	6,347	6,388	6,346	6,362	6,376	6,421	6,460	6,492	6,532	6,564	6,620	6,669	6,712	6,757
PS	8,138	8,215	8,252	8,320	8,304	8,298	8,263	8,251	8,298	8,352	8,373	8,392	8,359	8,383	8,449	8,509
RECO	316	317	318	321	320	320	319	318	320	321	322	322	321	321	323	325
UGI	162	164	164	165	162	162	162	162	162	162	163	163	163	164	164	165
DIVERSITY - MID-ATLANTIC(-)	938	1,087	998	1,072	771	900	942	1,033	1,037	845	846	851	1,003	1,033	1,028	835
PJM MID-ATLANTIC	47,275	47,622	48,026	48,396	48,547	48,487	48,413	48,450	48,819	49,330	49,561	49,787	49,736	50,019	50,418	50,978
FE-EAST	9,361	9,443	9,511	9,596	9,628	9,607	9,582	9,588	9,660	9,762	9,825	9,868	9,845	9,886	9,983	10,115
PLGRP	6,339	6,426	6,489	6,517	6,496	6,498	6,524	6,556	6,584	6,621	6,670	6,695	6,760	6,797	6,843	6,891

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.
Fall season indicates peak from September, October, November.

Table B-4

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

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
AEP	20,550	20,867	21,090	21,294	21,310	21,460	21,583	21,780	21,964	22,162	22,381	22,607	22,773	22,981	23,196	23,463
APS	7,717	7,921	8,030	8,135	8,136	8,178	8,208	8,262	8,333	8,396	8,449	8,515	8,563	8,640	8,711	8,774
ATSI	11,069	11,067	11,100	11,279	11,285	11,333	11,352	11,292	11,442	11,529	11,591	11,648	11,581	11,646	11,817	11,916
COMED	18,021	18,269	18,353	18,635	18,686	18,804	18,898	19,024	19,209	19,445	19,612	19,787	19,922	20,043	20,318	20,558
DAYTON	2,922	2,949	2,969	3,019	3,043	3,059	3,055	3,059	3,089	3,152	3,179	3,201	3,189	3,203	3,249	3,315
DEOK	4,760	4,803	4,813	4,898	4,929	4,957	4,976	4,998	5,034	5,101	5,151	5,185	5,214	5,217	5,295	5,370
DLCO	2,478	2,491	2,496	2,530	2,536	2,540	2,528	2,523	2,545	2,572	2,582	2,594	2,579	2,584	2,618	2,646
EKPC	1,940	1,964	1,973	1,978	1,984	2,002	2,020	2,039	2,035	2,043	2,066	2,078	2,106	2,120	2,120	2,127
DIVERSITY - WESTERN(-)	1,513	1,943	2,134	2,124	1,554	1,720	1,659	1,955	2,146	1,796	1,787	1,869	2,000	2,386	2,228	1,977
PJM WESTERN	67,944	68,388	68,690	69,644	70,355	70,613	70,961	71,022	71,505	72,604	73,224	73,746	73,927	74,048	75,096	76,192
DOM	17,296	17,925	18,459	18,774	18,754	18,852	18,954	19,266	19,548	19,731	19,901	20,006	20,252	20,509	20,688	20,847
DIVERSITY - INTERREGIONAL(-)	4,091	4,174	4,575	4,462	4,328	4,288	4,015	4,197	4,433	4,331	4,350	4,184	4,229	4,443	4,448	4,181
PJM RTO	128,424	129,761	130,600	132,352	133,328	133,664	134,313	134,541	135,439	137,334	138,336	139,355	139,686	140,133	141,754	143,836

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.
Fall season indicates peak from September, October, November.

Table B-5

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

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	MID-ATLANTIC DIVERSITY	PJM MID-ATLANTIC
Jan 2016	1,626	5,941	3,413	3,766	2,593	6,654	2,814	5,386	7,210	6,712	227	192	712	45,822
Feb 2016	1,561	5,615	3,262	3,674	2,493	6,365	2,778	5,156	6,819	6,499	219	182	946	43,677
Mar 2016	1,379	5,045	2,918	3,206	2,369	5,874	2,576	4,574	6,377	5,983	206	167	1,502	39,172
Apr 2016	1,337	4,720	2,689	3,323	2,221	5,828	2,400	4,274	5,860	6,452	220	147	2,595	36,876
May 2016	1,699	5,523	3,018	4,142	2,430	6,667	2,466	5,254	5,934	7,635	296	147	1,793	43,418
Jun 2016	2,238	6,564	3,715	5,439	2,801	8,132	2,780	6,279	6,801	9,508	379	174	670	54,140
Jul 2016	2,524	6,945	3,991	5,968	2,940	8,547	2,890	6,563	7,193	10,090	407	188	1,072	57,174
Aug 2016	2,416	6,724	3,830	5,424	2,834	8,116	2,766	6,372	6,863	9,365	367	173	723	54,527
Sep 2016	1,946	5,848	3,263	4,541	2,490	7,151	2,581	5,583	6,194	8,138	316	157	933	47,275
Oct 2016	1,417	4,645	2,633	3,403	2,139	5,772	2,375	4,298	5,695	6,373	241	144	1,520	37,615
Nov 2016	1,387	4,742	2,695	3,240	2,250	5,787	2,505	4,340	6,146	6,039	213	162	481	39,025
Dec 2016	1,613	5,522	3,171	3,820	2,518	6,499	2,806	5,207	6,815	6,752	238	187	576	44,572
	AE	**BGE**	**DPL**	**JCPL**	**METED**	**PECO**	**PENLC**	**PEPCO**	**PL**	**PS**	**RECO**	**UGI**	**DIVERSITY**	**MID-ATLANTIC**
Jan 2017	1,632	5,994	3,461	3,822	2,637	6,770	2,828	5,455	7,297	6,801	228	194	615	46,504
Feb 2017	1,569	5,658	3,317	3,717	2,533	6,490	2,793	5,211	6,916	6,589	220	184	772	44,425
Mar 2017	1,388	5,095	2,956	3,258	2,418	5,968	2,594	4,600	6,481	6,072	208	170	1,446	39,762
Apr 2017	1,336	4,756	2,707	3,293	2,261	5,839	2,423	4,327	5,912	6,252	228	149	2,354	37,129
May 2017	1,711	5,565	3,068	4,258	2,476	6,779	2,480	5,328	6,021	7,777	298	149	1,605	44,305
Jun 2017	2,244	6,601	3,762	5,516	2,849	8,259	2,807	6,326	6,878	9,582	382	176	690	54,692
Jul 2017	2,530	6,989	4,030	6,038	2,975	8,658	2,900	6,614	7,270	10,173	409	190	1,040	57,736
Aug 2017	2,417	6,753	3,860	5,485	2,878	8,216	2,785	6,420	6,905	9,417	369	174	665	55,014
Sep 2017	1,956	5,870	3,310	4,607	2,526	7,249	2,587	5,618	6,290	8,215	317	158	1,081	47,622
Oct 2017	1,430	4,742	2,720	3,543	2,205	6,027	2,391	4,375	5,830	6,678	247	146	1,501	38,833
Nov 2017	1,401	4,797	2,742	3,293	2,293	5,884	2,520	4,389	6,242	6,104	215	164	548	39,496
Dec 2017	1,617	5,551	3,213	3,870	2,559	6,584	2,800	5,257	6,884	6,797	235	189	533	45,023
	AE	**BGE**	**DPL**	**JCPL**	**METED**	**PECO**	**PENLC**	**PEPCO**	**PL**	**PS**	**RECO**	**UGI**	**DIVERSITY**	**MID-ATLANTIC**
Jan 2018	1,640	6,044	3,507	3,880	2,679	6,858	2,836	5,514	7,385	6,868	229	196	626	47,010
Feb 2018	1,579	5,709	3,365	3,786	2,582	6,573	2,800	5,272	6,999	6,656	221	186	719	45,009
Mar 2018	1,387	5,120	2,981	3,290	2,452	5,996	2,598	4,639	6,547	6,095	208	171	1,569	39,915
Apr 2018	1,343	4,819	2,786	3,518	2,298	6,068	2,422	4,360	6,020	6,696	235	150	2,880	37,835
May 2018	1,717	5,606	3,098	4,325	2,512	6,870	2,491	5,389	6,093	7,852	300	151	1,618	44,786
Jun 2018	2,251	6,653	3,776	5,565	2,881	8,342	2,807	6,343	6,932	9,594	380	177	757	54,944
Jul 2018	2,534	7,060	4,055	6,096	3,019	8,745	2,904	6,630	7,338	10,234	411	191	1,023	58,194
Aug 2018	2,424	6,827	3,892	5,535	2,906	8,294	2,787	6,445	6,974	9,435	369	175	697	55,366
Sep 2018	1,960	5,892	3,342	4,650	2,557	7,321	2,585	5,636	6,347	8,252	318	159	993	48,026
Oct 2018	1,442	4,785	2,838	3,671	2,243	6,178	2,407	4,425	5,983	6,853	250	147	1,904	39,318
Nov 2018	1,402	4,827	2,780	3,321	2,315	5,951	2,533	4,413	6,283	6,130	215	164	529	39,805
Dec 2018	1,633	5,607	3,259	3,914	2,607	6,668	2,826	5,326	6,982	6,882	237	191	746	45,386

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.

Table B-5

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

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	WESTERN DIVERSITY	PJM WESTERN	DOM	INTER REGION DIVERSITY	PJM RTO
Jan 2016	22,506	8,526	10,549	15,433	2,848	4,422	2,158	2,602	1,227	67,817	17,431	827	130,243
Feb 2016	21,476	8,157	10,427	15,180	2,745	4,247	2,090	2,365	1,445	65,242	16,087	649	124,357
Mar 2016	20,452	7,765	9,698	13,803	2,548	3,905	1,989	2,057	1,818	60,399	15,912	809	114,674
Apr 2016	18,966	7,102	9,169	13,636	2,452	3,840	2,072	1,690	2,250	56,677	15,692	1,041	108,204
May 2016	19,557	7,383	10,409	16,703	2,750	4,433	2,340	1,564	2,533	62,606	17,013	3,519	119,518
Jun 2016	22,148	8,467	12,466	20,493	3,184	5,176	2,796	1,841	1,137	75,434	18,687	4,188	144,073
Jul 2016	23,006	8,817	12,921	22,001	3,403	5,436	2,893	1,924	1,572	78,829	19,531	3,403	152,131
Aug 2016	22,778	8,642	12,587	21,325	3,337	5,386	2,828	1,918	989	77,812	19,226	3,661	147,904
Sep 2016	20,550	7,717	11,069	18,021	2,922	4,760	2,478	1,716	1,289	67,944	17,296	4,091	128,424
Oct 2016	18,302	6,861	8,981	13,755	2,398	3,876	1,994	1,655	2,100	55,722	15,102	2,474	105,965
Nov 2016	19,315	7,306	9,395	13,931	2,504	3,794	1,946	1,940	1,186	58,945	14,793	1,867	110,896
Dec 2016	21,259	8,194	10,584	15,832	2,759	4,276	2,145	2,369	1,083	66,335	16,257	1,340	125,824
	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	DIVERSITY	WESTERN	DOM	DIVERSITY	PJM RTO
Jan 2017	22,889	8,778	10,657	15,661	2,901	4,489	2,180	2,634	1,199	68,990	18,063	1,075	132,482
Feb 2017	21,765	8,416	10,517	15,389	2,796	4,309	2,115	2,397	1,591	66,113	16,685	673	126,550
Mar 2017	20,806	8,012	9,796	14,081	2,594	3,976	2,002	2,090	1,817	61,540	16,415	1,977	115,740
Apr 2017	19,179	7,314	9,284	13,795	2,471	3,916	2,067	1,704	2,651	57,079	16,163	2,442	107,929
May 2017	19,840	7,586	10,499	16,948	2,797	4,487	2,359	1,578	2,489	63,605	17,508	3,973	121,445
Jun 2017	22,468	8,664	12,549	20,801	3,238	5,231	2,825	1,856	1,265	76,367	19,210	4,114	146,155
Jul 2017	23,309	9,014	13,004	22,216	3,453	5,500	2,918	1,947	1,589	79,772	20,052	3,411	154,149
Aug 2017	23,063	8,824	12,667	21,599	3,384	5,442	2,851	1,931	896	78,865	19,711	3,690	149,900
Sep 2017	20,867	7,921	11,067	18,269	2,949	4,803	2,491	1,718	1,697	68,388	17,925	4,174	129,761
Oct 2017	18,771	7,159	9,103	14,136	2,465	3,984	2,023	1,674	2,314	57,001	15,763	2,827	108,770
Nov 2017	19,788	7,543	9,493	14,164	2,545	3,867	1,964	1,964	1,251	60,077	15,460	2,064	112,969
Dec 2017	21,597	8,404	10,649	16,051	2,805	4,317	2,153	2,400	1,226	67,150	16,740	1,082	127,831
	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	DIVERSITY	WESTERN	DOM	DIVERSITY	PJM RTO
Jan 2018	23,295	9,009	10,747	15,940	2,955	4,549	2,195	2,665	1,306	70,049	18,622	1,036	134,645
Feb 2018	22,146	8,630	10,596	15,650	2,850	4,353	2,126	2,423	1,786	66,988	17,187	598	128,586
Mar 2018	21,200	8,151	9,873	14,282	2,640	4,041	2,016	2,112	1,851	62,464	17,019	2,198	117,200
Apr 2018	19,944	7,486	9,344	14,213	2,556	4,077	2,189	1,731	1,896	59,644	16,756	453	113,782
May 2018	20,211	7,719	10,597	17,183	2,844	4,562	2,381	1,594	2,513	64,578	18,223	4,015	123,572
Jun 2018	22,771	8,783	12,646	20,934	3,277	5,295	2,840	1,866	1,324	77,088	19,679	4,224	147,487
Jul 2018	23,584	9,127	13,089	22,438	3,496	5,566	2,938	1,960	1,564	80,634	20,499	3,414	155,913
Aug 2018	23,351	8,945	12,762	21,770	3,425	5,502	2,873	1,943	946	79,625	20,167	4,827	150,331
Sep 2018	21,090	8,030	11,100	18,353	2,969	4,813	2,496	1,731	1,892	68,690	18,459	4,575	130,600
Oct 2018	19,427	7,388	9,156	14,541	2,567	4,051	2,180	1,696	1,339	59,667	16,313	2,543	112,755
Nov 2018	20,134	7,723	9,538	14,290	2,574	3,916	1,985	1,973	1,179	60,954	16,011	2,401	114,369
Dec 2018	22,038	8,577	10,832	16,296	2,857	4,388	2,186	2,439	1,382	68,231	17,207	1,176	129,648

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.

Table B-6

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

	FE_EAST	PLGRP
Jan 2016	9,095	7,387
Feb 2016	8,878	7,000
Mar 2016	7,905	6,423
Apr 2016	7,488	5,866
May 2016	8,691	5,971
Jun 2016	10,893	6,975
Jul 2016	11,538	7,336
Aug 2016	10,955	7,036
Sep 2016	9,361	6,339
Oct 2016	7,605	5,802
Nov 2016	7,919	6,297
Dec 2016	9,132	7,003

	FE_EAST	PLGRP
Jan 2017	9,229	7,476
Feb 2017	8,983	7,084
Mar 2017	7,962	6,499
Apr 2017	7,511	5,886
May 2017	8,861	6,054
Jun 2017	10,990	7,054
Jul 2017	11,655	7,417
Aug 2017	11,038	7,079
Sep 2017	9,443	6,426
Oct 2017	7,812	5,932
Nov 2017	8,033	6,401
Dec 2017	9,208	7,073

	FE_EAST	PLGRP
Jan 2018	9,335	7,566
Feb 2018	9,103	7,173
Mar 2018	8,032	6,578
Apr 2018	7,656	6,016
May 2018	8,963	6,129
Jun 2018	11,072	7,107
Jul 2018	11,762	7,487
Aug 2018	11,107	7,149
Sep 2018	9,511	6,489
Oct 2018	7,966	6,096
Nov 2018	8,095	6,448
Dec 2018	9,314	7,158

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.

Table B-7

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

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
AE																
LIMITED	43	43														
EXTENDED SUMMER	61	61														
ANNUAL	0	0														
BASE			105	105												
CAPACITY PERFORMANCE			0	0	38	38	38	38	38	38	38	38	38	38	38	38
TOTAL LOAD MANAGEMENT	104	104	105	105	38	38	38	38	38	38	38	38	38	38	38	38
BGE																
LIMITED	617	622														
EXTENDED SUMMER	62	62														
ANNUAL	4	4														
BASE			691	691												
CAPACITY PERFORMANCE			4	4	259	258	258	259	261	263	264	264	264	267	268	269
TOTAL LOAD MANAGEMENT	683	688	695	695	259	258	258	259	261	263	264	264	264	267	268	269
DPL																
LIMITED	149	150														
EXTENDED SUMMER	85	86														
ANNUAL	0	0														
BASE			238	238												
CAPACITY PERFORMANCE			0	0	88	88	88	88	88	89	89	89	89	90	90	90
TOTAL LOAD MANAGEMENT	234	236	238	238	88	88	88	88	88	89	89	89	89	90	90	90
JCPL																
LIMITED	116	116														
EXTENDED SUMMER	33	34														
ANNUAL	0	0														
BASE			152	152												
CAPACITY PERFORMANCE			0	0	56	56	56	56	56	56	56	57	56	57	57	57
TOTAL LOAD MANAGEMENT	149	150	152	152	56	56	56	56	56	56	56	57	56	57	57	57
METED																
LIMITED	166	169														
EXTENDED SUMMER	51	51														
ANNUAL	0	0														
BASE			223	225												
CAPACITY PERFORMANCE			0	0	83	83	83	83	85	85	86	87	87	88	90	92
TOTAL LOAD MANAGEMENT	217	220	223	225	83	83	83	83	85	85	86	87	87	88	90	92

DR Forecast accounts for the transition from Limited, Extended Summer and Annual DR to Base and Capacity Performance (CP) DR in Delivery Year (DY) 2018, and then to only CP DR in DY 2020.
DR Forecast is based on the average ratio of committed DR (by DR product) to past forecasted peak in the last 3 DYs (2013, 2014 and 2015) multiplied by the forecasted summer peaks in Table B-1.
The following assumptions are made to forecast the new products that begin in DY 2018:
-For DYs 2018 and 2019, Limited and Extended Summer DR are assumed to become Base DR while Annual DR is assumed to become CP DR.
-For DY 2020 and beyond, Annual DR is assumed to become CP DR. In addition, a portion of Base DR is assumed to become CP DR. This portion is computed based on the ratio of Coupled Base DR Offers to Total Cleared Base DR Offers from the 2018 BRA results.
Full transition to Base and CP DR for regions with FRR DR (AEP, DEOK) is completed in DY 2019.
Winter load management is equal to Annual for Delivery Years 2016 and 2017. After those Delivery Years, winter load management is equal to Capacity Performance.

Table B-7 (Continued)

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

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
PECO																
LIMITED	314	319														
EXTENDED SUMMER	103	104														
ANNUAL	0	0														
BASE			427	429												
CAPACITY PERFORMANCE			0	0	158	158	159	159	161	162	164	164	166	167	169	171
TOTAL LOAD MANAGEMENT	417	423	427	429	158	158	159	159	161	162	164	164	166	167	169	171
PENLC																
LIMITED	224	225														
EXTENDED SUMMER	53	53														
ANNUAL	0	0														
BASE			278	279												
CAPACITY PERFORMANCE			0	0	102	102	102	102	102	102	103	103	103	103	103	103
TOTAL LOAD MANAGEMENT	277	278	278	279	102	102	102	102	102	102	103	103	103	103	103	103
PEPCO																
LIMITED	209	210														
EXTENDED SUMMER	238	240														
ANNUAL	0	0														
BASE			452	454												
CAPACITY PERFORMANCE			0	0	168	167	167	168	168	169	171	170	171	171	173	175
TOTAL LOAD MANAGEMENT	447	450	452	454	168	167	167	168	168	169	171	170	171	171	173	175
PL																
LIMITED	501	506														
EXTENDED SUMMER	141	143														
ANNUAL	1	1														
BASE			655	658												
CAPACITY PERFORMANCE			1	1	242	243	243	244	246	247	249	251	252	254	256	258
TOTAL LOAD MANAGEMENT	643	650	656	659	242	243	243	244	246	247	249	251	252	254	256	258
PS																
LIMITED	277	280														
EXTENDED SUMMER	87	88														
ANNUAL	16	16														
BASE			370	370												
CAPACITY PERFORMANCE			16	16	152	152	151	151	151	152	152	152	152	152	153	154
TOTAL LOAD MANAGEMENT	380	384	386	386	152	152	151	151	151	152	152	152	152	152	153	154

DR Forecast accounts for the transition from Limited, Extended Summer and Annual DR to Base and Capacity Performance (CP) DR in Delivery Year (DY) 2018, and then to only CP DR in DY 2020.
DR Forecast is based on the average ratio of committed DR (by DR product) to past forecasted peak in the last 3 DYs (2013, 2014 and 2015) multiplied by the forecasted summer peaks in Table B-1.
The following assumptions are made to forecast the new products that begin in DY 2018:
-For DYs 2018 and 2019, Limited and Extended Summer DR are assumed to become Base DR while Annual DR is assumed to become CP DR.
-For DY 2020 and beyond, Annual DR is assumed to become CP DR. In addition, a portion of Base DR is assumed to become CP DR. This portion is computed based on the ratio of Coupled Base DR Offers to Total Cleared Base DR Offers from the 2018 BRA results.
Full transition to Base and CP DR for regions with FRR DR (AEP, DEOK) is completed in DY 2019.
Winter load management is equal to Annual for Delivery Years 2016 and 2017. After those Delivery Years, winter load management is equal to Capacity Performance.

Table B-7 (Continued)

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

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
RECO																
LIMITED	4	4														
EXTENDED SUMMER	1	1														
ANNUAL	0	0														
BASE			5	5												
CAPACITY PERFORMANCE			0	0	2	2	2	2	2	2	2	2	2	2	2	2
TOTAL LOAD MANAGEMENT	5	5	5	5	2	2	2	2	2	2	2	2	2	2	2	2
UGI																
LIMITED	0	0														
EXTENDED SUMMER	0	0														
ANNUAL	0	0														
BASE			0	0												
CAPACITY PERFORMANCE			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																
LIMITED	2,620	2,644														
EXTENDED SUMMER	915	923														
ANNUAL	21	21														
BASE			3,596	3,606												
CAPACITY PERFORMANCE			21	21	1,348	1,347	1,347	1,350	1,358	1,365	1,374	1,377	1,380	1,389	1,399	1,409
TOTAL LOAD MANAGEMENT	3,556	3,588	3,617	3,627	1,348	1,347	1,347	1,350	1,358	1,365	1,374	1,377	1,380	1,389	1,399	1,409

DR Forecast accounts for the transition from Limited, Extended Summer and Annual DR to Base and Capacity Performance (CP) DR in Delivery Year (DY) 2018, and then to only CP DR in DY 2020.
DR Forecast is based on the average ratio of committed DR (by DR product) to past forecasted peak in the last 3 DYs (2013, 2014 and 2015) multiplied by the forecasted summer peaks in Table B-1.
The following assumptions are made to forecast the new products that begin in DY 2018:
-For DYs 2018 and 2019, Limited and Extended Summer DR are assumed to become Base DR while Annual DR is assumed to become CP DR.
-For DY 2020 and beyond, Annual DR is assumed to become CP DR. In addition, a portion of Base DR is assumed to become CP DR. This portion is computed based on the ratio of Coupled Base DR Offers to Total Cleared Base DR Offers from the 2018 BRA results.
Full transition to Base and CP DR for regions with FRR DR (AEP, DEOK) is completed in DY 2019.
Winter load management is equal to Annual for Delivery Years 2016 and 2017. After those Delivery Years, winter load management is equal to Capacity Performance.

Table B-7 (Continued)

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

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
AEP																
LIMITED	1,250	1,266	421													
EXTENDED SUMMER	71	72	0													
ANNUAL	39	40	0													
BASE			933	1,367												
CAPACITY PERFORMANCE			40	40	543	546	550	553	559	563	567	572	577	583	589	595
TOTAL LOAD MANAGEMENT	1,360	1,378	1,394	1,407	543	546	550	553	559	563	567	572	577	583	589	595
APS																
LIMITED	459	468														
EXTENDED SUMMER	149	153														
ANNUAL	6	6														
BASE			629	635												
CAPACITY PERFORMANCE			6	6	241	241	242	243	245	247	249	250	251	253	255	257
TOTAL LOAD MANAGEMENT	614	627	635	641	241	241	242	243	245	247	249	250	251	253	255	257
ATSI																
LIMITED	525	528														
EXTENDED SUMMER	235	237														
ANNUAL	26	26														
BASE			770	773												
CAPACITY PERFORMANCE			26	26	310	311	312	312	314	315	317	318	320	322	324	326
TOTAL LOAD MANAGEMENT	786	791	796	799	310	311	312	312	314	315	317	318	320	322	324	326
COMED																
LIMITED	773	779														
EXTENDED SUMMER	327	331														
ANNUAL	7	7														
BASE			1,122	1,131												
CAPACITY PERFORMANCE			7	7	423	425	428	430	434	438	441	445	448	451	457	463
TOTAL LOAD MANAGEMENT	1,107	1,117	1,129	1,138	423	425	428	430	434	438	441	445	448	451	457	463
DAYTON																
LIMITED	106	108														
EXTENDED SUMMER	8	8														
ANNUAL	7	7														
BASE			117	118												
CAPACITY PERFORMANCE			7	7	51	51	51	51	52	52	53	53	53	54	54	54
TOTAL LOAD MANAGEMENT	121	123	124	125	51	51	51	51	52	52	53	53	53	54	54	54

DR Forecast accounts for the transition from Limited, Extended Summer and Annual DR to Base and Capacity Performance (CP) DR in Delivery Year (DY) 2018, and then to only CP DR in DY 2020.
DR Forecast is based on the average ratio of committed DR (by DR product) to past forecasted peak in the last 3 DYs (2013, 2014 and 2015) multiplied by the forecasted summer peaks in Table B-1.
The following assumptions are made to forecast the new products that begin in DY 2018:
-For DYs 2018 and 2019, Limited and Extended Summer DR are assumed to become Base DR while Annual DR is assumed to become CP DR.
-For DY 2020 and beyond, Annual DR is assumed to become CP DR. In addition, a portion of Base DR is assumed to become CP DR. This portion is computed based on the ratio of Coupled Base DR Offers to Total Cleared Base DR Offers from the 2018 BRA results.
Full transition to Base and CP DR for regions with FRR DR (AEP, DEOK) is completed in DY 2019.
Winter load management is equal to Annual for Delivery Years 2016 and 2017. After those Delivery Years, winter load management is equal to Capacity Performance.

Table B-7 (Continued)

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

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
DEOK																
LIMITED	183	186	37													
EXTENDED SUMMER	49	49	0													
ANNUAL	0	0	0													
BASE			201	240												
CAPACITY PERFORMANCE			0	0	88	89	89	90	91	91	92	93	93	94	95	96
TOTAL LOAD MANAGEMENT	232	235	238	240	88	89	89	90	91	91	92	93	93	94	95	96
DLCO																
LIMITED	84	85														
EXTENDED SUMMER	20	20														
ANNUAL	1	1														
BASE			106	106												
CAPACITY PERFORMANCE			1	1	40	40	40	40	40	40	40	40	41	41	41	41
TOTAL LOAD MANAGEMENT	105	106	107	107	40	40	40	40	40	40	40	40	41	41	41	41
EKPC																
LIMITED	111	112														
EXTENDED SUMMER	0	0														
ANNUAL	0	0														
BASE			113	114												
CAPACITY PERFORMANCE			0	0	42	42	42	43	43	43	43	44	44	44	44	44
TOTAL LOAD MANAGEMENT	111	112	113	114	42	42	42	43	43	43	43	44	44	44	44	44
PJM WESTERN																
LIMITED	3,491	3,532	458													
EXTENDED SUMMER	859	870	0													
ANNUAL	86	87	0													
BASE			3,991	4,484												
CAPACITY PERFORMANCE			87	87	1,738	1,745	1,754	1,762	1,778	1,789	1,802	1,815	1,827	1,842	1,859	1,876
TOTAL LOAD MANAGEMENT	4,436	4,489	4,536	4,571	1,738	1,745	1,754	1,762	1,778	1,789	1,802	1,815	1,827	1,842	1,859	1,876

DR Forecast accounts for the transition from Limited, Extended Summer and Annual DR to Base and Capacity Performance (CP) DR in Delivery Year (DY) 2018, and then to only CP DR in DY 2020.
DR Forecast is based on the average ratio of committed DR (by DR product) to past forecasted peak in the last 3 DYs (2013, 2014 and 2015) multiplied by the forecasted summer peaks in Table B-1.
The following assumptions are made to forecast the new products that begin in DY 2018:
-For DYs 2018 and 2019, Limited and Extended Summer DR are assumed to become Base DR while Annual DR is assumed to become CP DR.
-For DY 2020 and beyond, Annual DR is assumed to become CP DR. In addition, a portion of Base DR is assumed to become CP DR. This portion is computed based on the ratio of Coupled Base DR Offers to Total Cleared Base DR Offers from the 2018 BRA results.
Full transition to Base and CP DR for regions with FRR DR (AEP, DEOK) is completed in DY 2019.
Winter load management is equal to Annual for Delivery Years 2016 and 2017. After those Delivery Years, winter load management is equal to Capacity Performance.

Table B-7 (Continued)

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

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
DOM																
LIMITED	695	714														
EXTENDED SUMMER	59	60														
ANNUAL	31	32														
BASE			791	804												
CAPACITY PERFORMANCE			33	33	330	332	335	338	342	345	348	351	355	358	362	366
TOTAL LOAD MANAGEMENT	785	806	824	837	330	332	335	338	342	345	348	351	355	358	362	366
PJM RTO																
LIMITED	6,806	6,890	458													
EXTENDED SUMMER	1,833	1,853	0													
ANNUAL	138	140	0													
BASE			8,378	8,894												
CAPACITY PERFORMANCE			141	141	3,416	3,424	3,436	3,450	3,478	3,499	3,524	3,543	3,562	3,589	3,620	3,651
TOTAL LOAD MANAGEMENT	8,777	8,883	8,977	9,035	3,416	3,424	3,436	3,450	3,478	3,499	3,524	3,543	3,562	3,589	3,620	3,651

DR Forecast accounts for the transition from Limited, Extended Summer and Annual DR to Base and Capacity Performance (CP) DR in Delivery Year (DY) 2018, and then to only CP DR in DY 2020.
DR Forecast is based on the average ratio of committed DR (by DR product) to past forecasted peak in the last 3 DYs (2013, 2014 and 2015) multiplied by the forecasted summer peaks in Table B-1.
The following assumptions are made to forecast the new products that begin in DY 2018:
-For DYs 2018 and 2019, Limited and Extended Summer DR are assumed to become Base DR while Annual DR is assumed to become CP DR.
-For DY 2020 and beyond, Annual DR is assumed to become CP DR. In addition, a portion of Base DR is assumed to become CP DR. This portion is computed based on the ratio of Coupled Base DR Offers to Total Cleared Base DR Offers from the 2018 BRA results.
Full transition to Base and CP DR for regions with FRR DR (AEP, DEOK) is completed in DY 2019.
Winter load management is equal to Annual for Delivery Years 2016 and 2017. After those Delivery Years, winter load management is equal to Capacity Performance.

Table B-8

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

Zone	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
AE	69	74	75	77	78	80	83	86	90	97	107	118	130	144	159	173
BGE	36	47	59	68	72	73	74	76	78	82	87	94	103	116	131	146
DPL	40	47	57	66	71	77	86	96	104	112	120	130	142	158	178	205
JCPL	100	107	110	112	115	118	122	127	134	145	161	180	200	223	246	270
METED	10	11	12	13	14	15	16	16	17	18	18	19	20	21	22	23
PECO	13	15	18	20	23	25	26	28	29	31	32	34	35	37	40	43
PENLC	4	6	8	9	11	13	14	15	16	17	18	19	20	22	23	25
PEPCO	24	32	40	46	49	50	52	53	55	58	61	66	72	81	90	100
PL	29	32	35	38	42	44	46	48	50	53	55	57	59	61	65	69
PS	125	136	141	145	149	154	160	169	180	197	220	249	280	315	351	387
RECO	3	3	3	4	4	4	4	4	5	5	6	7	8	9	11	12
UGI	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1
AEP	11	16	21	27	34	41	50	59	68	78	88	96	105	114	125	137
APS	14	18	23	28	31	33	36	38	41	44	48	52	57	63	70	78
ATSI	18	22	27	32	37	43	48	53	59	65	71	73	74	76	77	80
COMED	17	22	26	30	33	39	46	53	61	69	77	84	92	100	108	116
DAYTON	3	4	5	6	7	9	10	11	12	13	15	15	15	16	16	16
DEOK	4	5	7	8	9	11	13	14	16	18	20	21	21	21	22	22
DLCO	2	3	4	5	6	7	8	8	9	10	10	11	11	12	13	14
EKPC	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	2
DOM	51	73	86	104	126	149	177	208	240	273	307	343	382	423	469	518
PJM RTO	574	676	759	839	914	986	1,070	1,165	1,267	1,385	1,523	1,669	1,829	2,013	2,217	2,441

Note: Adjustment values presented here are reflected in all summer peak forecast values.
Adjustments reflect the impact of historical distributed solar generation and forecasted distributed solar generation.

Table B-9

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

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
AE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BGE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DPL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
JCPL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
METED	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PECO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PENLC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PEPCO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RECO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
UGI	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AEP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
APS	120	220	250	280	280	270	260	260	250	240	230	230	220	210	210	200
ATSI	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
DAYTON	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEOK	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
EKPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DOM	240	410	560	680	730	810	860	900	930	960	990	1,010	1,020	1,040	1,050	1,050
PJM RTO	360	630	810	960	1,010	1,080	1,120	1,160	1,180	1,200	1,220	1,240	1,240	1,250	1,260	1,250

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

Table B-10

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

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
AE	2,435	2,442	2,447	2,445	2,430	2,418	2,414	2,415	2,415	2,414	2,409	2,405	2,404	2,402	2,392	2,389
BGE	6,663	6,716	6,765	6,758	6,778	6,763	6,773	6,813	6,833	6,894	6,917	6,924	6,964	7,014	7,013	7,072
DPL	3,838	3,878	3,907	3,916	3,917	3,908	3,912	3,926	3,941	3,966	3,977	3,982	4,003	4,023	4,027	4,038
JCPL	5,749	5,820	5,883	5,891	5,859	5,860	5,856	5,871	5,886	5,905	5,916	5,946	5,958	5,996	5,993	6,020
METED	2,824	2,856	2,907	2,937	2,931	2,940	2,950	2,960	3,009	3,034	3,058	3,087	3,100	3,148	3,183	3,211
PECO	8,255	8,363	8,454	8,497	8,500	8,491	8,527	8,587	8,646	8,694	8,796	8,837	8,923	9,010	9,075	9,144
PENLC	2,764	2,774	2,776	2,779	2,781	2,769	2,768	2,772	2,773	2,772	2,786	2,785	2,790	2,794	2,798	2,799
PEPCO	6,288	6,333	6,353	6,387	6,415	6,404	6,384	6,407	6,426	6,471	6,512	6,525	6,529	6,560	6,581	6,631
PL	6,906	6,982	7,051	7,083	7,059	7,073	7,096	7,128	7,167	7,205	7,243	7,303	7,350	7,412	7,452	7,501
PS	9,719	9,787	9,863	9,868	9,841	9,818	9,810	9,820	9,805	9,830	9,843	9,869	9,879	9,896	9,875	9,907
RECO	388	391	393	393	392	391	391	391	391	392	392	392	393	393	393	393
UGI	180	182	183	183	182	181	181	181	182	182	183	183	184	184	185	185
AEP	22,139	22,439	22,706	22,901	22,876	23,017	23,164	23,369	23,574	23,723	23,891	24,119	24,362	24,594	24,809	24,990
APS	8,495	8,696	8,812	8,891	8,895	8,920	8,958	9,022	9,074	9,132	9,184	9,245	9,314	9,384	9,442	9,511
ATSI	12,396	12,476	12,545	12,617	12,581	12,618	12,649	12,692	12,767	12,801	12,845	12,922	12,977	13,057	13,143	13,193
COMED	21,212	21,456	21,693	21,855	21,864	21,976	22,120	22,271	22,451	22,623	22,782	22,994	23,199	23,347	23,603	23,799
DAYTON	3,229	3,276	3,317	3,344	3,330	3,341	3,359	3,385	3,416	3,435	3,456	3,482	3,514	3,550	3,577	3,600
DEOK	5,193	5,258	5,329	5,374	5,386	5,402	5,432	5,477	5,527	5,571	5,605	5,643	5,698	5,754	5,807	5,854
DLCO	2,772	2,796	2,818	2,827	2,817	2,819	2,822	2,831	2,840	2,848	2,858	2,874	2,889	2,905	2,917	2,928
EKPC	1,858	1,880	1,895	1,906	1,908	1,916	1,918	1,938	1,952	1,960	1,968	1,980	1,994	2,007	2,020	2,028
DOM	18,827	19,347	19,813	20,104	20,145	20,332	20,503	20,716	20,916	21,094	21,269	21,491	21,723	21,963	22,127	22,274
PJM RTO	152,130	154,148	155,910	156,956	156,887	157,357	157,987	158,972	159,991	160,946	161,890	162,988	164,147	165,393	166,412	167,467
PJM MID-ATLANTIC	56,009	56,524	56,982	57,137	57,085	57,016	57,062	57,271	57,474	57,759	58,032	58,238	58,477	58,832	58,967	59,290
EASTERN MID-ATLANTIC	30,384	30,681	30,947	31,010	30,939	30,886	30,910	31,010	31,084	31,201	31,333	31,431	31,560	31,720	31,755	31,891
SOUTHERN MID-ATLANTIC	12,951	13,049	13,118	13,145	13,193	13,167	13,157	13,220	13,259	13,365	13,429	13,449	13,493	13,574	13,594	13,703

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.
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.
Summer season indicates peak from June, July, August.

Table B-11

PJM CONTROL AREA - JANUARY 2016
SUMMER TOTAL INTERNAL DEMAND FORECAST (MW) FOR EACH NERC REGION
2016 - 2026

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Annual Growth Rate (10 yr)
PJM - RELIABILITY FIRST												
TOTAL INTERNAL DEMAND	130,676	132,150	133,454	134,171	134,028	134,319	134,753	135,548	136,330	137,062	137,809	0.5%
% TOTAL		1.1%	1.0%	0.5%	-0.1%	0.2%	0.3%	0.6%	0.6%	0.5%	0.5%	
CONTRACTUALLY INTERRUPTIBLE	7,604	7,686	7,759	7,802	2,938	2,943	2,952	2,962	2,986	3,003	3,025	
DIRECT CONTROL	277	279	281	282	106	107	107	107	107	108	108	
TOTAL LOAD MANAGEMENT	7,881	7,965	8,040	8,084	3,044	3,050	3,059	3,069	3,093	3,111	3,133	
NET INTERNAL DEMAND	122,795	124,185	125,414	126,087	130,984	131,269	131,694	132,479	133,237	133,951	134,676	0.9%
% NET		1.1%	1.0%	0.5%	3.9%	0.2%	0.3%	0.6%	0.6%	0.5%	0.5%	
PJM - SERC												
TOTAL INTERNAL DEMAND	21,455	21,999	22,459	22,787	22,859	23,039	23,233	23,427	23,661	23,885	24,082	1.2%
% TOTAL		2.5%	2.1%	1.5%	0.3%	0.8%	0.8%	0.8%	1.0%	0.9%	0.8%	
CONTRACTUALLY INTERRUPTIBLE	792	811	828	840	329	330	333	337	340	343	345	
DIRECT CONTROL	104	107	109	111	43	44	44	44	45	45	46	
TOTAL LOAD MANAGEMENT	896	918	937	951	372	374	377	381	385	388	391	
NET INTERNAL DEMAND	20,559	21,081	21,522	21,836	22,487	22,665	22,856	23,046	23,276	23,497	23,691	1.4%
% NET		2.5%	2.1%	1.5%	3.0%	0.8%	0.8%	0.8%	1.0%	0.9%	0.8%	
PJM RTO												
TOTAL INTERNAL DEMAND	152,131	154,149	155,913	156,958	156,887	157,358	157,986	158,975	159,991	160,947	161,891	0.6%
% TOTAL		1.3%	1.1%	0.7%	-0.0%	0.3%	0.4%	0.6%	0.6%	0.6%	0.6%	
CONTRACTUALLY INTERRUPTIBLE	8,396	8,497	8,587	8,642	3,266	3,274	3,285	3,299	3,326	3,346	3,370	
DIRECT CONTROL	381	386	390	393	150	150	151	151	152	153	154	
TOTAL LOAD MANAGEMENT	8,777	8,883	8,977	9,035	3,416	3,424	3,436	3,450	3,478	3,499	3,524	
NET INTERNAL DEMAND	143,354	145,266	146,936	147,923	153,471	153,934	154,550	155,525	156,513	157,448	158,367	1.0%
% NET		1.3%	1.1%	0.7%	3.8%	0.3%	0.4%	0.6%	0.6%	0.6%	0.6%	

Notes:
Total Internal Demand = projected PJM seasonal peak load at normal peak weather conditions in the absence of any load reductions due to load management, voltage reductions or voluntary curtailments.
Contractually Interruptible = Firm Service Level + Guaranteed Load Drop
The above forecasts incorporate all load in the PJM Control Area, including members and non-members.
All average growth rates are calculated from the first year of the forecast (2016).

Table B-11 (Continued)

PJM CONTROL AREA - JANUARY 2016
SUMMER TOTAL INTERNAL DEMAND FORECAST (MW) FOR EACH NERC REGION
2027 - 2031

	2027	2028	2029	2030	2031	Annual Growth Rate (15 yr)
PJM - RELIABILITY FIRST						
TOTAL INTERNAL DEMAND	138,680	139,616	140,622	141,415	142,280	0.6%
% TOTAL	0.6%	0.7%	0.7%	0.6%	0.6%	
CONTRACTUALLY INTERRUPTIBLE	3,039	3,054	3,078	3,104	3,130	
DIRECT CONTROL	109	109	109	110	111	
TOTAL LOAD MANAGEMENT	3,148	3,163	3,187	3,214	3,241	
NET INTERNAL DEMAND	135,532	136,453	137,435	138,201	139,039	0.8%
% NET	0.6%	0.7%	0.7%	0.6%	0.6%	
PJM - SERC						
TOTAL INTERNAL DEMAND	24,308	24,529	24,770	24,997	25,189	1.1%
% TOTAL	0.9%	0.9%	1.0%	0.9%	0.8%	
CONTRACTUALLY INTERRUPTIBLE	349	352	355	359	362	
DIRECT CONTROL	46	47	47	47	48	
TOTAL LOAD MANAGEMENT	395	399	402	406	410	
NET INTERNAL DEMAND	23,913	24,130	24,368	24,591	24,779	1.3%
% NET	0.9%	0.9%	1.0%	0.9%	0.8%	
PJM RTO						
TOTAL INTERNAL DEMAND	162,988	164,145	165,392	166,412	167,469	0.6%
% TOTAL	0.7%	0.7%	0.8%	0.6%	0.6%	
CONTRACTUALLY INTERRUPTIBLE	3,388	3,406	3,433	3,462	3,492	
DIRECT CONTROL	155	156	156	158	159	
TOTAL LOAD MANAGEMENT	3,543	3,562	3,589	3,620	3,651	
NET INTERNAL DEMAND	159,445	160,583	161,803	162,792	163,818	0.9%
% NET	0.7%	0.7%	0.8%	0.6%	0.6%	

Notes:
Total Internal Demand = projected PJM seasonal peak load at normal peak weather conditions in the absence of any load reductions due to load management, voltage reductions or voluntary curtailments.
Contractually Interruptible = Firm Service Level + Guaranteed Load Drop
The above forecasts incorporate all load in the PJM Control Area, including members and non-members.
All average growth rates are calculated from the first year of the forecast (2016).

Table B-12

PJM CONTROL AREA - JANUARY 2016
WINTER TOTAL INTERNAL DEMAND FORECAST (MW) FOR EACH NERC REGION
2015/16 - 2025/26

	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	Annual Growth Rate (10 yr)
PJM - RELIABILITY FIRST												
TOTAL INTERNAL DEMAND	110,210	111,785	113,358	114,337	114,155	114,366	114,984	115,484	116,410	116,964	117,643	0.7%
% TOTAL		1.4%	1.4%	0.9%	-0.2%	0.2%	0.5%	0.4%	0.8%	0.5%	0.6%	
CONTRACTUALLY INTERRUPTIBLE	102	103	103	103	2,938	2,943	2,952	2,962	2,986	3,003	3,025	
DIRECT CONTROL	5	5	5	5	106	107	107	107	107	108	108	
TOTAL LOAD MANAGEMENT	5	5	5	5	106	107	107	107	107	108	108	
NET INTERNAL DEMAND	110,205	111,780	113,353	114,332	114,049	114,259	114,877	115,377	116,303	116,856	117,535	0.6%
% NET		1.4%	1.4%	0.9%	-0.2%	0.2%	0.5%	0.4%	0.8%	0.5%	0.6%	
PJM - SERC												
TOTAL INTERNAL DEMAND	20,033	20,697	21,287	21,742	21,867	22,036	22,279	22,526	22,780	22,998	23,269	1.5%
% TOTAL		3.3%	2.9%	2.1%	0.6%	0.8%	1.1%	1.1%	1.1%	1.0%	1.2%	
CONTRACTUALLY INTERRUPTIBLE	27	28	29	29	329	330	333	337	340	343	345	
DIRECT CONTROL	4	4	4	4	43	44	44	44	45	45	46	
TOTAL LOAD MANAGEMENT	31	32	33	33	372	374	377	381	385	388	391	
NET INTERNAL DEMAND	20,002	20,665	21,254	21,709	21,495	21,662	21,902	22,145	22,395	22,610	22,878	1.4%
% NET		3.3%	2.9%	2.1%	-1.0%	0.8%	1.1%	1.1%	1.1%	1.0%	1.2%	
PJM RTO												
TOTAL INTERNAL DEMAND	130,243	132,482	134,645	136,079	136,022	136,402	137,263	138,010	139,190	139,962	140,912	0.8%
% TOTAL		1.7%	1.6%	1.1%	-0.0%	0.3%	0.6%	0.5%	0.9%	0.6%	0.7%	
CONTRACTUALLY INTERRUPTIBLE	130	132	132	132	3,266	3,274	3,285	3,299	3,326	3,346	3,370	
DIRECT CONTROL	8	8	9	9	150	150	151	151	152	153	154	
TOTAL LOAD MANAGEMENT	138	140	141	141	3,416	3,424	3,436	3,450	3,478	3,499	3,524	
NET INTERNAL DEMAND	130,105	132,342	134,504	135,938	132,606	132,978	133,827	134,560	135,712	136,463	137,388	0.5%
% NET		1.7%	1.6%	1.1%	-2.5%	0.3%	0.6%	0.5%	0.9%	0.6%	0.7%	

Notes:
Total Internal Demand = projected PJM seasonal peak load at normal peak weather conditions in the absence of any load reductions due to load management, voltage reductions or voluntary curtailments.
Contractually Interruptible = Firm Service Level + Guaranteed Load Drop
The above forecasts incorporate all load in the PJM Control Area, including members and non-members.
All average growth rates are calculated from the first year of the forecast (2015/16).

Table B-12 (Continued)

PJM CONTROL AREA - JANUARY 2016
WINTER TOTAL INTERNAL DEMAND FORECAST (MW) FOR EACH NERC REGION
2026/27 - 2030/31

	26/27	27/28	28/29	29/30	30/31	Annual Growth Rate (15 yr)
PJM - RELIABILITY FIRST						
TOTAL INTERNAL DEMAND	118,458	119,353	119,860	120,993	121,705	0.7%
% TOTAL	0.7%	0.8%	0.4%	0.9%	0.6%	
CONTRACTUALLY INTERRUPTIBLE	3,039	3,054	3,078	3,104	3,130	
DIRECT CONTROL	109	109	109	110	111	
TOTAL LOAD MANAGEMENT	109	109	109	110	111	
NET INTERNAL DEMAND	118,349	119,244	119,751	120,883	121,594	0.7%
% NET	0.7%	0.8%	0.4%	0.9%	0.6%	
PJM - SERC						
TOTAL INTERNAL DEMAND	23,529	23,796	24,057	24,310	24,520	1.4%
% TOTAL	1.1%	1.1%	1.1%	1.1%	0.9%	
CONTRACTUALLY INTERRUPTIBLE	349	352	355	359	362	
DIRECT CONTROL	46	47	47	47	48	
TOTAL LOAD MANAGEMENT	395	399	402	406	410	
NET INTERNAL DEMAND	23,134	23,397	23,655	23,904	24,110	1.3%
% NET	1.1%	1.1%	1.1%	1.1%	0.9%	
PJM RTO						
TOTAL INTERNAL DEMAND	141,987	143,149	143,917	145,303	146,225	0.8%
% TOTAL	0.8%	0.8%	0.5%	1.0%	0.6%	
CONTRACTUALLY INTERRUPTIBLE	3,388	3,406	3,433	3,462	3,492	
DIRECT CONTROL	155	156	156	158	159	
TOTAL LOAD MANAGEMENT	3,543	3,562	3,589	3,620	3,651	
NET INTERNAL DEMAND	138,444	139,587	140,328	141,683	142,574	0.6%
% NET	0.8%	0.8%	0.5%	1.0%	0.6%	

Notes:
Total Internal Demand = projected PJM seasonal peak load at normal peak weather conditions in the absence of any load reductions due to load management, voltage reductions or voluntary curtailments.
Contractually Interruptible = Firm Service Level + Guaranteed Load Drop
The above forecasts incorporate all load in the PJM Control Area, including members and non-members.
All average growth rates are calculated from the first year of the forecast (2015/16).

Table C-1

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

BASE (50/50) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2016	18,950	23,491	19,975	21,160
2017	19,162	23,726	20,106	21,455
2018	19,366	23,924	20,239	21,670
2019	19,450	24,038	20,438	21,809
2020	19,286	24,017	20,480	21,762
2021	19,315	24,017	20,494	21,780
2022	19,495	24,085	20,524	21,875
2023	19,587	24,181	20,559	21,934
2024	19,688	24,302	20,711	22,042
2025	19,689	24,439	20,905	22,121
2026	19,769	24,562	21,028	22,222
2027	19,872	24,682	21,153	22,352
2028	20,158	24,832	21,202	22,532
2029	20,295	25,005	21,317	22,637
2030	20,311	25,127	21,505	22,749
2031	20,361	25,275	21,719	22,858

EXTREME WEATHER (90/10) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2016	20,493	24,995	21,534	22,050
2017	20,709	25,237	21,747	22,289
2018	20,908	25,258	21,935	22,545
2019	21,009	25,563	22,036	22,674
2020	20,957	25,628	21,936	22,613
2021	20,981	25,625	22,023	22,628
2022	21,077	25,620	22,097	22,694
2023	21,174	25,761	22,189	22,780
2024	21,284	25,887	22,315	22,888
2025	21,288	26,134	22,432	22,982
2026	21,502	26,260	22,491	23,079
2027	21,643	26,388	22,696	23,201
2028	21,810	26,487	22,849	23,335
2029	21,961	26,463	23,012	23,484
2030	22,064	26,812	23,143	23,589
2031	22,157	27,079	23,282	23,711

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.
Spring season indicates peak from March, April, May.
Summer season indicates peak from June, July, August.
Fall season indicates peak from September, October, November.
Winter season indicates peak from December, January, February.

Table C-2

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

BASE (50/50) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2016	11,286	13,028	11,234	12,734
2017	11,416	13,161	11,370	12,880
2018	11,534	13,268	11,456	13,023
2019	11,588	13,335	11,555	13,094
2020	11,540	13,318	11,550	13,048
2021	11,573	13,334	11,496	13,036
2022	11,609	13,380	11,533	13,097
2023	11,645	13,429	11,570	13,112
2024	11,695	13,501	11,656	13,184
2025	11,734	13,574	11,774	13,231
2026	11,794	13,658	11,818	13,258
2027	11,862	13,749	11,864	13,324
2028	11,935	13,833	11,917	13,420
2029	12,004	13,935	11,966	13,473
2030	12,046	14,023	12,080	13,536
2031	12,095	14,117	12,189	13,602

EXTREME WEATHER (90/10) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2016	11,779	13,822	11,938	13,151
2017	11,870	13,975	12,078	13,304
2018	12,044	14,070	12,193	13,449
2019	12,102	14,155	12,256	13,518
2020	12,053	14,142	12,219	13,467
2021	12,035	14,150	12,239	13,459
2022	12,059	14,203	12,285	13,490
2023	12,105	14,268	12,344	13,531
2024	12,185	14,344	12,420	13,589
2025	12,246	14,471	12,493	13,630
2026	12,306	14,514	12,533	13,676
2027	12,374	14,614	12,642	13,741
2028	12,438	14,717	12,732	13,809
2029	12,516	14,796	12,832	13,881
2030	12,560	14,910	12,908	13,941
2031	12,649	15,063	12,999	13,995

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.
Spring season indicates peak from March, April, May.
Summer season indicates peak from June, July, August.
Fall season indicates peak from September, October, November.
Winter season indicates peak from December, January, February.

Table C-3

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

BASE (50/50) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2016	22,695	31,278	25,044	22,194
2017	23,261	31,598	25,263	22,499
2018	23,535	31,716	25,457	22,740
2019	23,641	31,924	25,742	22,922
2020	22,846	31,885	25,796	22,799
2021	22,744	31,709	25,765	22,732
2022	23,277	31,855	25,596	22,781
2023	23,613	31,930	25,622	22,852
2024	23,732	32,019	25,868	22,949
2025	23,583	32,190	26,148	23,004
2026	23,277	32,315	26,261	23,092
2027	23,321	32,292	26,385	23,211
2028	24,095	32,509	26,245	23,365
2029	24,244	32,568	26,376	23,496
2030	24,309	32,732	26,692	23,626
2031	24,200	32,928	26,977	23,706

EXTREME WEATHER (90/10) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2016	26,215	33,422	27,466	22,860
2017	26,534	33,995	27,807	23,140
2018	26,813	34,014	27,937	23,412
2019	26,910	34,304	28,187	23,524
2020	26,824	34,160	28,184	23,417
2021	26,803	34,072	27,961	23,394
2022	26,853	34,069	27,968	23,408
2023	26,935	34,359	28,098	23,475
2024	27,024	34,420	28,335	23,569
2025	27,124	34,604	28,783	23,617
2026	27,235	34,640	28,653	23,704
2027	27,379	34,712	28,603	23,835
2028	27,506	35,019	28,709	23,963
2029	27,625	34,925	28,826	24,095
2030	27,716	35,217	29,204	24,198
2031	27,831	35,447	29,699	24,302

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.
Spring season indicates peak from March, April, May.
Summer season indicates peak from June, July, August.
Fall season indicates peak from September, October, November.
Winter season indicates peak from December, January, February.

Table C-4

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

BASE (50/50) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2016	10,485	13,393	11,363	11,306
2017	10,601	13,491	11,402	11,415
2018	10,727	13,578	11,473	11,491
2019	10,777	13,624	11,555	11,541
2020	10,626	13,662	11,614	11,589
2021	10,625	13,652	11,621	11,604
2022	10,742	13,635	11,620	11,649
2023	10,816	13,678	11,606	11,686
2024	10,902	13,741	11,696	11,700
2025	10,904	13,857	11,816	11,794
2026	10,867	13,911	11,873	11,845
2027	10,914	13,957	11,926	11,905
2028	11,092	13,967	11,897	11,989
2029	11,167	14,043	11,961	12,009
2030	11,218	14,097	12,074	12,069
2031	11,234	14,223	12,183	12,163

EXTREME WEATHER (90/10) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2016	11,509	14,269	12,306	11,802
2017	11,600	14,391	12,405	11,903
2018	11,684	14,426	12,482	12,016
2019	11,727	14,453	12,531	12,067
2020	11,716	14,467	12,455	12,066
2021	11,729	14,484	12,509	12,089
2022	11,761	14,532	12,541	12,124
2023	11,805	14,582	12,600	12,170
2024	11,860	14,586	12,659	12,223
2025	11,905	14,665	12,715	12,272
2026	11,962	14,738	12,710	12,326
2027	12,027	14,810	12,819	12,385
2028	12,089	14,906	12,893	12,452
2029	12,159	14,944	12,962	12,524
2030	12,206	14,981	13,036	12,581
2031	12,249	15,061	13,092	12,642

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.
Spring season indicates peak from March, April, May.
Summer season indicates peak from June, July, August.
Fall season indicates peak from September, October, November.
Winter season indicates peak from December, January, February.

Table D-1

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

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
AE	2,637	2,650	2,646	2,658	2,633	2,624	2,623	2,624	2,630	2,633	2,619	2,616	2,620	2,610	2,615	2,616
BGE	7,366	7,431	7,443	7,449	7,460	7,471	7,498	7,532	7,531	7,573	7,615	7,650	7,703	7,721	7,735	7,775
DPL	4,159	4,205	4,219	4,248	4,229	4,236	4,245	4,255	4,273	4,296	4,296	4,318	4,341	4,348	4,371	4,381
JCPL	6,480	6,561	6,588	6,652	6,589	6,586	6,600	6,614	6,654	6,682	6,663	6,694	6,725	6,731	6,791	6,830
METED	3,043	3,119	3,120	3,178	3,179	3,195	3,186	3,239	3,260	3,291	3,321	3,358	3,391	3,387	3,452	3,490
PECO	9,008	9,143	9,208	9,259	9,261	9,295	9,352	9,408	9,443	9,524	9,599	9,687	9,781	9,836	9,916	10,022
PENLC	3,026	3,049	3,046	3,045	3,043	3,038	3,042	3,049	3,043	3,051	3,058	3,063	3,077	3,077	3,080	3,090
PEPCO	6,903	6,960	6,983	7,004	7,007	7,014	7,034	7,050	7,055	7,092	7,123	7,160	7,203	7,223	7,247	7,287
PL	7,556	7,673	7,698	7,725	7,777	7,742	7,794	7,856	7,837	7,973	7,996	8,014	8,117	8,126	8,170	8,317
PS	10,873	10,988	10,901	11,038	11,000	10,883	10,995	11,010	10,973	11,021	11,015	10,947	11,101	10,948	11,073	11,146
RECO	444	448	452	449	448	448	448	448	447	448	449	450	451	453	451	452
UGI	202	205	206	207	205	204	203	204	205	205	205	206	207	208	209	210
DIVERSITY - MID-ATLANTIC(-)	533	610	520	0	412	309	529	603	0	153	456	317	622	525	2	147
PJM MID-ATLANTIC	61,164	61,822	61,990	62,912	62,419	62,427	62,491	62,686	63,351	63,636	63,503	63,846	64,095	64,143	65,108	65,469
FE-EAST	12,422	12,564	12,661	12,714	12,688	12,671	12,699	12,740	12,795	12,860	12,912	12,962	13,028	13,097	13,162	13,248
PLGRP	7,758	7,878	7,903	7,932	7,981	7,946	7,997	8,060	8,042	8,178	8,201	8,220	8,324	8,333	8,379	8,527

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.
Summer season indicates peak from June, July, August.

Table D-1

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

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
AEP	23,944	24,296	24,429	24,609	24,676	24,895	25,097	25,295	25,345	25,578	25,790	26,122	26,380	26,517	26,691	26,960
APS	9,007	9,245	9,358	9,441	9,420	9,460	9,514	9,611	9,645	9,680	9,740	9,824	9,942	10,005	10,060	10,094
ATSI	13,453	13,569	13,619	13,653	13,661	13,705	13,764	13,817	13,833	13,910	13,976	14,060	14,154	14,221	14,265	14,361
COMED	24,083	24,288	24,449	24,691	24,641	24,788	25,042	25,137	25,321	25,537	25,667	25,906	26,159	26,339	26,568	26,821
DAYTON	3,548	3,587	3,618	3,653	3,640	3,657	3,693	3,705	3,732	3,752	3,778	3,810	3,847	3,873	3,906	3,933
DEOK	5,677	5,742	5,786	5,826	5,845	5,880	5,932	5,957	5,990	6,042	6,088	6,143	6,194	6,244	6,288	6,348
DLCO	3,026	3,057	3,068	3,075	3,072	3,074	3,083	3,091	3,091	3,106	3,121	3,138	3,157	3,167	3,177	3,196
EKPC	2,043	2,064	2,072	2,089	2,088	2,101	2,115	2,127	2,140	2,154	2,159	2,178	2,190	2,204	2,218	2,235
DIVERSITY - WESTERN(-)	431	559	236	196	157	335	533	520	203	297	242	423	533	293	162	262
PJM WESTERN	84,350	85,289	86,163	86,841	86,886	87,225	87,707	88,220	88,894	89,462	90,077	90,758	91,490	92,277	93,011	93,686
DOM	20,430	20,989	21,383	21,682	21,783	21,986	22,191	22,384	22,528	22,771	22,976	23,222	23,461	23,661	23,831	24,049
DIVERSITY - INTERREGIONAL(-)	2,250	2,060	1,728	2,335	2,029	2,130	2,332	1,999	2,251	2,315	1,945	2,090	2,028	1,897	2,317	2,376
PJM RTO	163,694	166,040	167,808	169,100	169,059	169,508	170,057	171,291	172,522	173,554	174,611	175,736	177,018	178,184	179,633	180,828

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.
Summer season indicates peak from June, July, August.

Table D-2

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

	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31
AE	1,674	1,679	1,685	1,685	1,671	1,667	1,663	1,662	1,663	1,663	1,665	1,670	1,675	1,679	1,682	1,683
BGE	6,185	6,230	6,281	6,304	6,297	6,309	6,324	6,348	6,372	6,399	6,427	6,455	6,487	6,519	6,546	6,578
DPL	3,565	3,613	3,659	3,682	3,683	3,694	3,707	3,728	3,749	3,773	3,794	3,817	3,841	3,869	3,891	3,919
JCPL	3,846	3,902	3,955	3,993	3,946	3,930	3,934	3,944	3,952	3,940	3,951	3,970	4,011	4,018	4,078	4,061
METED	2,662	2,716	2,758	2,790	2,784	2,782	2,787	2,813	2,830	2,839	2,858	2,876	2,898	2,924	2,967	2,970
PECO	6,841	6,938	7,023	7,064	7,029	7,037	7,059	7,094	7,132	7,164	7,201	7,246	7,292	7,344	7,377	7,424
PENLC	2,871	2,886	2,896	2,906	2,883	2,881	2,883	2,884	2,891	2,883	2,884	2,882	2,890	2,889	2,910	2,893
PEPCO	5,625	5,673	5,735	5,763	5,769	5,783	5,800	5,825	5,851	5,877	5,908	5,940	5,974	6,011	6,037	6,072
PL	7,428	7,509	7,596	7,630	7,606	7,610	7,622	7,649	7,681	7,709	7,743	7,782	7,820	7,867	7,894	7,939
PS	6,818	6,888	6,945	6,979	6,947	6,918	6,930	6,944	6,952	6,950	6,971	7,003	7,035	7,053	7,118	7,100
RECO	236	239	240	241	238	238	239	240	240	238	238	239	240	240	243	240
UGI	201	202	204	204	202	201	201	201	201	201	201	201	201	201	202	202
DIVERSITY - MID-ATLANTIC(-)	578	333	282	332	308	393	328	349	314	407	433	492	318	328	427	439
PJM MID-ATLANTIC	47,374	48,142	48,695	48,909	48,747	48,657	48,821	48,983	49,200	49,229	49,408	49,589	50,046	50,286	50,518	50,642
FE-EAST	9,350	9,462	9,568	9,644	9,568	9,558	9,565	9,592	9,627	9,637	9,675	9,722	9,772	9,829	9,895	9,896
PLGRP	7,628	7,711	7,800	7,834	7,808	7,811	7,823	7,850	7,882	7,909	7,943	7,983	8,021	8,068	8,095	8,140

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.
Winter season indicates peak from December, January, February.

Table D-2

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

2015/16 - 2030/31

	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31
AEP	23,839	24,231	24,701	24,881	24,931	25,092	25,336	25,507	25,799	25,971	26,209	26,455	26,753	27,031	27,211	27,478
APS	8,980	9,231	9,465	9,553	9,592	9,643	9,689	9,748	9,819	9,876	9,938	10,000	10,076	10,145	10,197	10,273
ATSI	10,833	10,921	11,021	11,091	11,055	11,073	11,108	11,160	11,216	11,266	11,308	11,357	11,404	11,461	11,513	11,562
COMED	16,027	16,266	16,486	16,683	16,642	16,697	16,803	16,937	17,089	17,244	17,372	17,500	17,663	17,802	17,995	18,136
DAYTON	2,961	3,010	3,065	3,096	3,080	3,085	3,105	3,127	3,152	3,170	3,195	3,214	3,242	3,269	3,292	3,309
DEOK	4,660	4,720	4,784	4,807	4,793	4,853	4,923	4,918	4,957	4,960	5,003	5,073	5,143	5,157	5,161	5,202
DLCO	2,202	2,222	2,240	2,250	2,238	2,235	2,237	2,246	2,252	2,252	2,260	2,269	2,278	2,288	2,299	2,301
EKPC	2,916	2,946	2,984	3,003	3,020	3,041	3,060	3,079	3,101	3,127	3,151	3,174	3,196	3,218	3,242	3,273
DIVERSITY - WESTERN(-)	1,083	922	976	1,003	1,095	1,228	1,088	1,099	1,090	1,293	1,349	1,372	1,199	1,137	1,259	1,478
PJM WESTERN	71,335	72,625	73,770	74,361	74,256	74,491	75,173	75,623	76,295	76,573	77,087	77,670	78,556	79,234	79,651	80,056
DOM	18,509	19,128	19,673	20,058	20,204	20,365	20,584	20,820	21,050	21,277	21,498	21,736	21,972	22,222	22,433	22,664
DIVERSITY - INTERREGIONAL(-)	371	748	785	816	730	541	803	766	854	560	466	420	852	870	821	555
PJM RTO	136,847	139,147	141,353	142,512	142,477	142,972	143,775	144,660	145,691	146,519	147,527	148,575	149,722	150,872	151,781	152,807

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation and prior to reductions for load management.
Winter season indicates peak from December, January, February.

Table E-1

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION 2016 - 2026

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Annual Growth Rate (10 yr)
AE	10,399	10,407	10,441	10,441	10,387	10,328	10,315	10,309	10,340	10,303	10,282	(0.1%)
		0.1%	0.3%	0.0%	-0.5%	-0.6%	-0.1%	-0.1%	0.3%	-0.4%	-0.2%	
BGE	34,075	34,236	34,461	34,568	34,640	34,644	34,789	34,934	35,200	35,259	35,402	0.4%
		0.5%	0.7%	0.3%	0.2%	0.0%	0.4%	0.4%	0.8%	0.2%	0.4%	
DPL	19,108	19,277	19,439	19,519	19,561	19,551	19,608	19,671	19,816	19,846	19,918	0.4%
		0.9%	0.8%	0.4%	0.2%	-0.1%	0.3%	0.3%	0.7%	0.2%	0.4%	
JCPL	22,880	23,151	23,437	23,531	23,383	23,260	23,288	23,337	23,471	23,453	23,491	0.3%
		1.2%	1.2%	0.4%	-0.6%	-0.5%	0.1%	0.2%	0.6%	-0.1%	0.2%	
METED	16,014	16,245	16,483	16,607	16,610	16,617	16,729	16,842	17,028	17,113	17,259	0.8%
		1.4%	1.5%	0.8%	0.0%	0.0%	0.7%	0.7%	1.1%	0.5%	0.9%	
PECO	41,882	42,434	42,989	43,274	43,236	43,211	43,435	43,692	44,121	44,290	44,585	0.6%
		1.3%	1.3%	0.7%	-0.1%	-0.1%	0.5%	0.6%	1.0%	0.4%	0.7%	
PENLC	18,062	18,049	18,082	18,065	18,129	18,079	18,086	18,071	18,118	18,089	18,116	0.0%
		-0.1%	0.2%	-0.1%	0.4%	-0.3%	0.0%	-0.1%	0.3%	-0.2%	0.1%	
PEPCO	32,057	32,242	32,501	32,644	32,759	32,751	32,879	33,016	33,282	33,357	33,520	0.4%
		0.6%	0.8%	0.4%	0.4%	-0.0%	0.4%	0.4%	0.8%	0.2%	0.5%	
PL	41,380	41,835	42,339	42,563	42,583	42,526	42,710	42,905	43,282	43,400	43,680	0.5%
		1.1%	1.2%	0.5%	0.0%	-0.1%	0.4%	0.5%	0.9%	0.3%	0.6%	
PS	45,085	45,430	45,811	45,934	45,880	45,678	45,734	45,772	45,953	45,922	45,997	0.2%
		0.8%	0.8%	0.3%	-0.1%	-0.4%	0.1%	0.1%	0.4%	-0.1%	0.2%	
RECO	1,535	1,537	1,542	1,541	1,546	1,539	1,538	1,537	1,541	1,539	1,536	0.0%
		0.1%	0.3%	-0.1%	0.3%	-0.5%	-0.1%	-0.1%	0.3%	-0.1%	-0.2%	
UGI	1,036	1,046	1,056	1,058	1,048	1,042	1,042	1,042	1,045	1,041	1,044	0.1%
		1.0%	1.0%	0.2%	-0.9%	-0.6%	0.0%	0.0%	0.3%	-0.4%	0.3%	
PJM MID-ATLANTIC	283,513	285,889	288,581	289,745	289,762	289,226	290,153	291,128	293,197	293,612	294,830	0.4%
		0.8%	0.9%	0.4%	0.0%	-0.2%	0.3%	0.3%	0.7%	0.1%	0.4%	
FE-EAST	56,956	57,445	58,002	58,203	58,122	57,956	58,103	58,250	58,617	58,655	58,866	0.3%
		0.9%	1.0%	0.3%	-0.1%	-0.3%	0.3%	0.3%	0.6%	0.1%	0.4%	
PLGRP	42,416	42,881	43,395	43,621	43,631	43,568	43,752	43,947	44,327	44,441	44,724	0.5%
		1.1%	1.2%	0.5%	0.0%	-0.1%	0.4%	0.4%	0.9%	0.3%	0.6%	

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation.
All average growth rates are calculated from the first year of the forecast (2016).

Table E-1 (Continued)

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION 2027 - 2031

	2027	2028	2029	2030	2031	Annual Growth Rate (15 yr)
AE	10,260	10,267	10,224	10,175	10,145	(0.2%)
	-0.2%	0.1%	-0.4%	-0.5%	-0.3%	
BGE	35,552	35,826	35,908	36,003	36,131	0.4%
	0.4%	0.8%	0.2%	0.3%	0.4%	
DPL	20,002	20,155	20,185	20,205	20,219	0.4%
	0.4%	0.8%	0.1%	0.1%	0.1%	
JCPL	23,558	23,700	23,736	23,733	23,800	0.3%
	0.3%	0.6%	0.2%	-0.0%	0.3%	
METED	17,428	17,643	17,794	17,916	18,089	0.8%
	1.0%	1.2%	0.9%	0.7%	1.0%	
PECO	44,946	45,444	45,765	46,049	46,426	0.7%
	0.8%	1.1%	0.7%	0.6%	0.8%	
PENLC	18,135	18,184	18,157	18,142	18,183	0.0%
	0.1%	0.3%	-0.1%	-0.1%	0.2%	
PEPCO	33,690	33,955	34,053	34,172	34,306	0.5%
	0.5%	0.8%	0.3%	0.3%	0.4%	
PL	43,996	44,439	44,705	44,911	45,230	0.6%
	0.7%	1.0%	0.6%	0.5%	0.7%	
PS	46,072	46,278	46,255	46,209	46,314	0.2%
	0.2%	0.4%	-0.0%	-0.1%	0.2%	
RECO	1,534	1,536	1,529	1,525	1,525	(0.0%)
	-0.1%	0.1%	-0.5%	-0.3%	0.0%	
UGI	1,045	1,052	1,054	1,055	1,056	0.1%
	0.1%	0.7%	0.2%	0.1%	0.1%	
PJM MID-ATLANTIC	296,218	298,479	299,365	300,095	301,424	0.4%
	0.5%	0.8%	0.3%	0.2%	0.4%	
FE-EAST	59,121	59,527	59,687	59,791	60,072	0.4%
	0.4%	0.7%	0.3%	0.2%	0.5%	
PLGRP	45,041	45,491	45,759	45,966	46,286	0.6%
	0.7%	1.0%	0.6%	0.5%	0.7%	

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation.
All average growth rates are calculated from the first year of the forecast (2016).

Table E-1

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2016 - 2026

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Annual Growth Rate (10 yr)
AEP	135,818	137,602	139,637	140,845	141,547	142,048	143,277	144,480	146,270	147,150	148,455	0.9%
		1.3%	1.5%	0.9%	0.5%	0.4%	0.9%	0.8%	1.2%	0.6%	0.9%	
APS	50,320	51,404	52,246	52,779	53,017	53,149	53,545	53,984	54,574	54,864	55,248	0.9%
		2.2%	1.6%	1.0%	0.5%	0.2%	0.7%	0.8%	1.1%	0.5%	0.7%	
ATSI	69,542	69,950	70,515	70,781	71,065	71,088	71,430	71,701	72,189	72,398	72,791	0.5%
		0.6%	0.8%	0.4%	0.4%	0.0%	0.5%	0.4%	0.7%	0.3%	0.5%	
COMED	102,549	103,923	105,470	106,426	106,868	107,220	108,178	109,139	110,522	111,347	112,470	0.9%
		1.3%	1.5%	0.9%	0.4%	0.3%	0.9%	0.9%	1.3%	0.7%	1.0%	
DAYTON	17,923	18,195	18,511	18,681	18,673	18,704	18,851	18,996	19,213	19,330	19,495	0.8%
		1.5%	1.7%	0.9%	-0.0%	0.2%	0.8%	0.8%	1.1%	0.6%	0.9%	
DEOK	27,894	28,224	28,616	28,859	28,993	29,080	29,321	29,555	29,891	30,067	30,325	0.8%
		1.2%	1.4%	0.8%	0.5%	0.3%	0.8%	0.8%	1.1%	0.6%	0.9%	
DLCO	14,790	14,899	15,024	15,075	15,092	15,064	15,107	15,150	15,241	15,264	15,344	0.4%
		0.7%	0.8%	0.3%	0.1%	-0.2%	0.3%	0.3%	0.6%	0.2%	0.5%	
EKPC	10,904	10,950	11,024	11,062	11,127	11,156	11,206	11,254	11,336	11,352	11,402	0.4%
		0.4%	0.7%	0.3%	0.6%	0.3%	0.4%	0.4%	0.7%	0.1%	0.4%	
PJM WESTERN	429,740	435,147	441,043	444,508	446,382	447,509	450,915	454,259	459,236	461,772	465,530	0.8%
		1.3%	1.4%	0.8%	0.4%	0.3%	0.8%	0.7%	1.1%	0.6%	0.8%	
DOM	98,082	100,776	103,471	105,239	105,845	106,527	107,641	108,827	110,405	111,352	112,503	1.4%
		2.7%	2.7%	1.7%	0.6%	0.6%	1.0%	1.1%	1.5%	0.9%	1.0%	
PJM RTO	811,335	821,812	833,095	839,492	841,989	843,262	848,709	854,214	862,838	866,736	872,863	0.7%
		1.3%	1.4%	0.8%	0.3%	0.2%	0.6%	0.6%	1.0%	0.5%	0.7%	

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation.
All average growth rates are calculated from the first year of the forecast (2016).

Table E-1 (Continued)

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2027 - 2031

	2027	2028	2029	2030	2031	Annual Growth Rate (15 yr)
AEP	149,863	151,812	153,102	154,347	155,849	0.9%
	0.9%	1.3%	0.8%	0.8%	1.0%	
APS	55,721	56,356	56,715	57,104	57,520	0.9%
	0.9%	1.1%	0.6%	0.7%	0.7%	
ATSI	73,214	73,788	74,076	74,332	74,788	0.5%
	0.6%	0.8%	0.4%	0.3%	0.6%	
COMED	113,669	115,173	116,264	117,188	118,373	1.0%
	1.1%	1.3%	0.9%	0.8%	1.0%	
DAYTON	19,678	19,922	20,090	20,216	20,398	0.9%
	0.9%	1.2%	0.8%	0.6%	0.9%	
DEOK	30,610	31,001	31,261	31,497	31,788	0.9%
	0.9%	1.3%	0.8%	0.8%	0.9%	
DLCO	15,426	15,552	15,602	15,650	15,733	0.4%
	0.5%	0.8%	0.3%	0.3%	0.5%	
EKPC	11,451	11,541	11,565	11,608	11,666	0.5%
	0.4%	0.8%	0.2%	0.4%	0.5%	
PJM WESTERN	469,632	475,145	478,675	481,942	486,115	0.8%
	0.9%	1.2%	0.7%	0.7%	0.9%	
DOM	113,755	115,405	116,556	117,562	118,629	1.3%
	1.1%	1.5%	1.0%	0.9%	0.9%	
PJM RTO	879,605	889,029	894,596	899,599	906,168	0.7%
	0.8%	1.1%	0.6%	0.6%	0.7%	

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation.
All average growth rates are calculated from the first year of the forecast (2016).

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 2016	872	3,141	1,767	1,956	1,452	3,665	1,648	2,850	3,944	3,788	124	102	25,309
Feb 2016	801	2,865	1,626	1,803	1,356	3,394	1,544	2,615	3,637	3,519	116	94	23,370
Mar 2016	798	2,750	1,531	1,783	1,333	3,355	1,535	2,548	3,527	3,527	118	91	22,896
Apr 2016	726	2,437	1,343	1,630	1,207	3,057	1,405	2,299	3,115	3,291	112	78	20,700
May 2016	770	2,490	1,385	1,694	1,231	3,130	1,428	2,396	3,124	3,424	119	76	21,267
Jun 2016	933	2,992	1,655	2,055	1,339	3,689	1,444	2,893	3,308	4,055	140	80	24,583
Jul 2016	1,148	3,367	1,908	2,439	1,466	4,186	1,537	3,237	3,624	4,632	161	89	27,794
Aug 2016	1,099	3,285	1,853	2,323	1,458	4,065	1,559	3,174	3,615	4,506	156	87	27,180
Sep 2016	843	2,632	1,489	1,809	1,227	3,315	1,412	2,584	3,121	3,650	127	75	22,284
Oct 2016	778	2,502	1,399	1,717	1,245	3,191	1,458	2,368	3,196	3,489	122	79	21,544
Nov 2016	767	2,591	1,444	1,716	1,266	3,217	1,466	2,417	3,326	3,417	116	85	21,828
Dec 2016	864	3,023	1,708	1,955	1,434	3,618	1,626	2,676	3,843	3,787	124	100	24,758
	AE	**BGE**	**DPL**	**JCPL**	**METED**	**PECO**	**PENLC**	**PEPCO**	**PL**	**PS**	**RECO**	**UGI**	**MID-ATLANTIC**
Jan 2017	878	3,184	1,801	1,997	1,487	3,747	1,662	2,895	4,029	3,852	125	104	25,761
Feb 2017	776	2,791	1,590	1,766	1,333	3,329	1,495	2,549	3,561	3,433	112	92	22,827
Mar 2017	801	2,773	1,552	1,813	1,360	3,412	1,541	2,573	3,584	3,572	118	92	23,191
Apr 2017	727	2,451	1,357	1,650	1,222	3,100	1,399	2,317	3,145	3,320	113	79	20,880
May 2017	772	2,508	1,400	1,719	1,254	3,182	1,434	2,420	3,173	3,461	119	77	21,519
Jun 2017	936	3,013	1,674	2,086	1,363	3,754	1,448	2,919	3,355	4,099	141	80	24,868
Jul 2017	1,151	3,383	1,924	2,468	1,486	4,245	1,536	3,259	3,663	4,671	161	90	28,037
Aug 2017	1,103	3,307	1,873	2,356	1,484	4,131	1,565	3,204	3,666	4,556	157	88	27,490
Sep 2017	845	2,647	1,502	1,831	1,246	3,359	1,412	2,603	3,157	3,677	127	76	22,482
Oct 2017	781	2,523	1,416	1,745	1,269	3,244	1,465	2,394	3,249	3,527	123	81	21,817
Nov 2017	771	2,615	1,463	1,745	1,290	3,271	1,473	2,443	3,377	3,458	117	87	22,110
Dec 2017	866	3,041	1,725	1,975	1,451	3,660	1,619	2,666	3,876	3,804	124	100	24,907
	AE	**BGE**	**DPL**	**JCPL**	**METED**	**PECO**	**PENLC**	**PEPCO**	**PL**	**PS**	**RECO**	**UGI**	**MID-ATLANTIC**
Jan 2018	883	3,219	1,825	2,032	1,520	3,815	1,674	2,936	4,098	3,907	126	106	26,141
Feb 2018	780	2,813	1,608	1,792	1,356	3,380	1,499	2,576	3,611	3,470	113	92	23,090
Mar 2018	802	2,787	1,564	1,832	1,374	3,449	1,535	2,588	3,613	3,595	118	93	23,350
Apr 2018	731	2,472	1,371	1,680	1,248	3,155	1,412	2,343	3,206	3,362	113	80	21,173
May 2018	775	2,524	1,412	1,744	1,274	3,226	1,437	2,441	3,216	3,496	120	78	21,743
Jun 2018	938	3,026	1,684	2,108	1,378	3,794	1,446	2,939	3,383	4,129	141	81	25,047
Jul 2018	1,156	3,412	1,940	2,500	1,516	4,315	1,549	3,299	3,727	4,728	163	91	28,396
Aug 2018	1,106	3,322	1,885	2,381	1,501	4,179	1,564	3,228	3,701	4,589	157	89	27,702
Sep 2018	846	2,660	1,509	1,850	1,260	3,392	1,412	2,617	3,186	3,696	127	77	22,632
Oct 2018	783	2,537	1,427	1,764	1,289	3,281	1,472	2,416	3,288	3,554	123	81	22,015
Nov 2018	773	2,630	1,474	1,763	1,307	3,308	1,476	2,462	3,410	3,484	118	87	22,292
Dec 2018	868	3,059	1,740	1,991	1,460	3,695	1,606	2,656	3,900	3,801	123	101	25,000

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation.

Table E-2

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

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	PJM WESTERN	DOM	PJM RTO
Jan 2016	12,706	4,787	6,188	8,879	1,606	2,482	1,274	1,202	39,124	9,018	73,451
Feb 2016	11,646	4,402	5,787	8,212	1,479	2,270	1,183	1,043	36,022	8,193	67,585
Mar 2016	11,370	4,285	5,792	8,207	1,459	2,215	1,195	922	35,445	7,774	66,115
Apr 2016	10,170	3,766	5,339	7,634	1,340	2,025	1,117	740	32,131	6,929	59,760
May 2016	10,445	3,816	5,481	7,886	1,387	2,111	1,158	734	33,018	7,223	61,508
Jun 2016	11,179	4,108	5,792	8,823	1,525	2,486	1,293	858	36,064	8,708	69,355
Jul 2016	12,031	4,438	6,263	10,053	1,661	2,712	1,415	935	39,508	9,644	76,946
Aug 2016	12,064	4,433	6,275	9,902	1,675	2,721	1,400	941	39,411	9,425	76,016
Sep 2016	10,380	3,780	5,453	8,006	1,397	2,179	1,168	756	33,119	7,789	63,192
Oct 2016	10,589	3,866	5,553	8,066	1,414	2,131	1,169	756	33,544	7,212	62,300
Nov 2016	10,861	4,038	5,520	7,962	1,406	2,132	1,156	888	33,963	7,473	63,264
Dec 2016	12,377	4,601	6,099	8,919	1,574	2,430	1,262	1,129	38,391	8,694	71,843
	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	WESTERN	DOM	PJM RTO
Jan 2017	13,006	4,933	6,282	9,067	1,647	2,533	1,294	1,216	39,978	9,322	75,061
Feb 2017	11,430	4,354	5,634	8,061	1,451	2,221	1,154	1,018	35,323	8,158	66,308
Mar 2017	11,579	4,399	5,853	8,368	1,487	2,252	1,210	929	36,077	8,036	67,304
Apr 2017	10,308	3,854	5,367	7,733	1,361	2,052	1,126	743	32,544	7,152	60,576
May 2017	10,619	3,918	5,537	8,029	1,415	2,144	1,170	739	33,571	7,464	62,554
Jun 2017	11,349	4,205	5,844	8,958	1,551	2,521	1,306	863	36,597	8,958	70,423
Jul 2017	12,174	4,529	6,293	10,184	1,683	2,742	1,425	940	39,970	9,888	77,895
Aug 2017	12,247	4,536	6,337	10,067	1,705	2,759	1,416	947	40,014	9,681	77,185
Sep 2017	10,525	3,869	5,493	8,124	1,421	2,207	1,179	758	33,576	8,018	64,076
Oct 2017	10,784	3,976	5,618	8,209	1,444	2,167	1,182	762	34,142	7,455	63,414
Nov 2017	11,054	4,146	5,579	8,103	1,437	2,168	1,169	896	34,552	7,719	64,381
Dec 2017	12,527	4,685	6,113	9,020	1,593	2,458	1,268	1,139	38,803	8,925	72,635
	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	WESTERN	DOM	PJM RTO
Jan 2018	13,269	5,037	6,370	9,256	1,686	2,583	1,311	1,229	40,741	9,615	76,497
Feb 2018	11,624	4,435	5,691	8,198	1,481	2,257	1,166	1,028	35,880	8,396	67,366
Mar 2018	11,707	4,463	5,874	8,463	1,508	2,274	1,215	934	36,438	8,263	68,051
Apr 2018	10,506	3,938	5,441	7,895	1,395	2,089	1,140	749	33,153	7,381	61,707
May 2018	10,780	3,986	5,588	8,163	1,442	2,176	1,182	742	34,059	7,684	63,486
Jun 2018	11,493	4,260	5,873	9,074	1,573	2,548	1,315	867	37,003	9,179	71,229
Jul 2018	12,403	4,616	6,390	10,380	1,721	2,788	1,445	948	40,691	10,140	79,227
Aug 2018	12,394	4,598	6,378	10,196	1,728	2,792	1,426	951	40,463	9,900	78,065
Sep 2018	10,647	3,924	5,525	8,226	1,441	2,233	1,186	761	33,943	8,208	64,783
Oct 2018	10,934	4,044	5,671	8,334	1,469	2,196	1,191	766	34,605	7,654	64,274
Nov 2018	11,198	4,208	5,621	8,213	1,459	2,195	1,178	903	34,975	7,913	65,180
Dec 2018	12,682	4,737	6,093	9,072	1,608	2,485	1,269	1,146	39,092	9,138	73,230

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation.

Table E-3

MONTHLY NET ENERGY FORECAST (GWh) FOR FE-EAST AND PLGRP

	FE_EAST	PLGRP
Jan 2016	5,056	4,046
Feb 2016	4,703	3,731
Mar 2016	4,651	3,618
Apr 2016	4,242	3,193
May 2016	4,353	3,200
Jun 2016	4,838	3,388
Jul 2016	5,442	3,713
Aug 2016	5,340	3,702
Sep 2016	4,448	3,196
Oct 2016	4,420	3,275
Nov 2016	4,448	3,411
Dec 2016	5,015	3,943

	FE_EAST	PLGRP
Jan 2017	5,146	4,133
Feb 2017	4,594	3,653
Mar 2017	4,714	3,676
Apr 2017	4,271	3,224
May 2017	4,407	3,250
Jun 2017	4,897	3,435
Jul 2017	5,490	3,753
Aug 2017	5,405	3,754
Sep 2017	4,489	3,233
Oct 2017	4,479	3,330
Nov 2017	4,508	3,464
Dec 2017	5,045	3,976

	FE_EAST	PLGRP
Jan 2018	5,226	4,204
Feb 2018	4,647	3,703
Mar 2018	4,741	3,706
Apr 2018	4,340	3,286
May 2018	4,455	3,294
Jun 2018	4,932	3,464
Jul 2018	5,565	3,818
Aug 2018	5,446	3,790
Sep 2018	4,522	3,263
Oct 2018	4,525	3,369
Nov 2018	4,546	3,497
Dec 2018	5,057	4,001

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation.

Table F-1

PJM RTO HISTORICAL PEAKS
(MW)

SUMMER

YEAR	NORMALIZED BASE	NORMALIZED COOLING	NORMALIZED TOTAL	UNRESTRICTED PEAK	PEAK DATE	TIME
1998				133,189	Tuesday, July 21, 1998	17:00
1999	89,051			141,321	Friday, July 30, 1999	17:00
2000	91,069	47,601	138,670	131,803	Wednesday, August 9, 2000	17:00
2001	92,113	50,072	142,185	150,929	Thursday, August 9, 2001	16:00
2002	92,690	54,195	146,885	150,830	Thursday, August 1, 2002	17:00
2003	93,653	52,902	146,555	145,233	Thursday, August 21, 2003	17:00
2004	95,169	53,091	148,260	139,219	Tuesday, August 3, 2004	17:00
2005	95,786	58,994	154,780	155,209	Tuesday, July 26, 2005	16:00
2006	95,253	62,147	157,400	166,866	Wednesday, August 2, 2006	17:00
2007	96,680	62,975	159,655	161,988	Wednesday, August 8, 2007	16:00
2008	97,144	62,426	159,570	150,560	Monday, June 9, 2008	17:00
2009	94,670	57,120	151,790	145,056	Monday, August 10, 2009	16:00
2010	93,133	61,112	154,245	157,188	Wednesday, July 7, 2010	17:00
2011	93,328	60,032	153,360	165,466	Thursday, July 21, 2011	17:00
2012	92,948	60,997	153,945	158,151	Tuesday, July 17, 2012	17:00
2013	92,464	56,936	149,400	159,039	Thursday, July 18, 2013	17:00
2014	91,837	58,268	150,105	141,402	Tuesday, June 17, 2014	18:00
2015	91,108	59,187	150,295	143,497	Tuesday, July 28, 2015	17:00

WINTER

YEAR	NORMALIZED BASE	NORMALIZED HEATING	NORMALIZED TOTAL	UNRESTRICTED PEAK	PEAK DATE	TIME
97/98				103,235	Wednesday, January 14, 1998	19:00
98/99	87,537			116,078	Tuesday, January 5, 1999	19:00
99/00	89,288	26,292	115,580	118,438	Thursday, January 27, 2000	20:00
00/01	91,324	26,416	117,740	118,051	Wednesday, December 20, 2000	19:00
01/02	92,410	23,610	116,020	112,221	Wednesday, January 2, 2002	19:00
02/03	92,591	27,879	120,470	129,972	Thursday, January 23, 2003	19:00
03/04	93,710	28,970	122,680	122,357	Friday, January 23, 2004	9:00
04/05	94,387	30,003	124,390	131,164	Monday, December 20, 2004	19:00
05/06	94,643	32,257	126,900	126,703	Wednesday, December 14, 2005	19:00
06/07	96,076	34,004	130,080	136,739	Monday, February 5, 2007	20:00
07/08	97,180	34,870	132,050	128,313	Wednesday, January 2, 2008	19:00
08/09	96,326	32,774	129,100	134,021	Friday, January 16, 2009	19:00
09/10	93,425	34,945	128,370	125,276	Monday, January 4, 2010	19:00
10/11	91,823	36,977	128,800	132,228	Tuesday, December 14, 2010	19:00
11/12	92,284	34,056	126,340	124,420	Tuesday, January 3, 2012	19:00
12/13	92,061	33,919	125,980	128,724	Tuesday, January 22, 2013	19:00
13/14	91,120	38,020	129,140	141,746	Tuesday, January 7, 2014	19:00
14/15	90,162	38,108	128,270	142,762	Friday, February 20, 2015	8:00

Notes:
Normalized values for 2005 - 2015 are calculated by PJM staff using a methodology described in Manual 19.
Normalized base values are calculated by PJM staff using a two-period average of peak loads on non-heating/non-coolong days.
All times are shown in hour ending Eastern Prevailing Time and historic peak values reflect current membership of the PJM RTO.

Table F-2

PJM RTO HISTORICAL NET ENERGY
(GWH)

YEAR	ENERGY	GROWTH RATE
1998	718,551	0.0%
1999	740,052	3.0%
2000	756,237	2.2%
2001	754,541	-0.2%
2002	782,300	3.7%
2003	780,693	-0.2%
2004	796,257	2.0%
2005	822,873	3.3%
2006	802,509	-2.5%
2007	835,782	4.1%
2008	822,098	-1.6%
2009	780,693	-5.0%
2010	819,576	5.0%
2011	805,366	-1.7%
2012	791,219	-1.8%
2013	794,484	0.4%
2014	795,519	0.1%

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

Table G-1

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

	5-Year (2016-21)	10-Year (2016-26)	15-Year (2016-31)
AE	0.8%	0.7%	0.7%
BGE	1.3%	1.2%	1.2%
DPL	1.6%	1.4%	1.3%
JCPL	1.2%	1.0%	1.0%
METED	1.7%	1.5%	1.5%
PECO	1.6%	1.4%	1.4%
PENLC	1.2%	1.1%	1.0%
PEPCO	1.6%	1.4%	1.3%
PL	1.6%	1.4%	1.3%
PS	1.2%	1.0%	1.0%
RECO	1.1%	0.9%	0.9%
UGI	1.0%	0.8%	0.7%
AEP	1.8%	1.6%	1.5%
APS	1.8%	1.6%	1.5%
ATSI	1.5%	1.3%	1.2%
COMED	1.6%	1.4%	1.3%
DAYTON	1.3%	1.1%	1.0%
DEOK	1.7%	1.5%	1.4%
DLCO	1.4%	1.2%	1.2%
EKPC	1.8%	1.6%	1.5%
DOM	1.7%	1.5%	1.4%
PJM RTO	1.6%	1.4%	1.3%

Source: Moody's Analytics, October, 2015

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

Working to Perfect the Flow of Energy

PJM Manual 19:

Load Forecasting and Analysis

Revision: 29

Effective Date: December 1, 2015

Prepared by

Resource Adequacy Planning

PJM Manual 19:

Load Forecasting and Analysis

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Approval

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Thomas A. Falin, Manager

Resource Adequacy Planning Department

Current Revision

Revision 29 (12/01/2015):

- Section 3: This extensive revision incorporates changes to the load forecast model to add variables to account for trends in appliance usage and energy efficiency, revisions in weather variables, and the introduction of an autoregressive error correction. It also adds assignment of Census Divisions to zones and updates the assignments of economic regions and weather stations to zones. Section 4: the weather normalization procedure used for coincident and non-coincident peaks has been revised. This revision serves as the required periodic review of the Manual.

Introduction

Welcome to the ***PJM Manual for Load Forecasting and Analysis***. In this Introduction you will find the following information:

- What you can expect from the PJM Manuals in general (see "*About PJM Manuals*").
- What you can expect from this PJM Manual (see "*About This Manual*")
- How to use this manual (see "*Using This Manual*").

About PJM Manuals

The PJM Manuals are the instructions, rules, procedures, and guidelines established by the PJM Office of the Interconnection for the operation, planning, and accounting requirements of the PJM RTO and the PJM Energy Market. The manuals are grouped under the following categories:

- Transmission
- PJM Energy Market
- Generation and transmission interconnection
- Reserve
- Accounting and billing
- PJM administrative services
- Miscellaneous

For a complete list of all PJM Manuals, go to www.pjm.com and select "Manuals" under the "Documents" pull-down menu.

About This Manual

The ***PJM Manual for Load Forecasting and Analysis*** is one of a series of manuals within the Reserve group of manuals. This manual focuses on load-related topics. This manual describes the data input requirements, the processing performed on the data, computer programs involved in processing the data, and the reports that are produced. It then describes processes used to analyze load data and produce a long-term planning forecast.

The ***PJM Manual for Load Forecasting and Analysis*** consists of four sections. These sections are listed in the table of contents beginning on page ii.

Intended Audience

The intended audiences for the ***PJM Manual for Load Forecasting and Analysis*** are:

Electric Distribution Company (EDC) planners — The EDC planners are responsible for supplying historical load data in the required format, for using coincident peaks to allocate normalized peaks, and for input data verification.

Load Serving Entity (LSE) planners — LSEs use allocated peaks and the Load Management systems to determine their capacity obligations.

PJM staff — PJM is responsible for the calculation of hourly PJM loads, normalizing PJM seasonal peaks, forecasting RTO and zonal peaks for capacity obligations, compiling the PJM Load Forecast Report, and administering Load Management. This information is used in calculating the capacity obligations.

Planning Committee members — The Planning Committee is responsible for the stakeholder review of the peak forecasts and techniques for their determination.

Reliability Assurance Agreement Signatories — The Markets Reliability Committee is involved in the review of rules, methods and parameters associated with Load Forecasting and Analysis.

References

There are several references to other documents that provide background or additional detail. The ***PJM Manual for Load Forecasting and Analysis*** does not replace any information in these reference documents. The following documents are the primary source of specific requirements and implementation details:

- Power Meter documentation
- eLRS documentation
- PJM Load Forecast Report
- PJM Manual for Emergency Operations (M-13)
- Reliability Assurance Agreement
- Behind-the-Meter Generation Business Rules (in Manual M-14D)
- Deemed Savings Estimates for Legacy Air Conditioning and Water Heating Direct Load Control Programs in PJM Region

Using This Manual

We believe that explaining concepts is just as important as presenting the procedures. This philosophy is reflected in the way we organize the material in this manual. We start each section with an overview. Then, we present details, procedures or references to procedures found in other PJM manuals. The following provides an orientation to the manual's structure.

What You Will Find In This Manual

- A table of contents that lists two levels of subheadings within each of the sections.
- An approval page that lists the required approvals and a brief outline of the current revision.
- Sections containing the specific guidelines, requirements, or procedures including PJM actions and PJM Member actions.
- Attachments that include additional supporting documents, forms, or tables in this PJM Manual.
- A section at the end detailing all previous revisions of this PJM manual.

Section 1: Overview

Welcome to the *Overview* section of the ***PJM Manual for Load Forecasting and Analysis***. In this section you will find the following information:

- An overview of the Load Forecasting and Analysis (see "Overview of Load Forecasting and Analysis")

1.1 Overview of Load Forecasting and Analysis

Load Forecasting and Analysis utilizes the PJM Power Meter load data, Load Management, PJM Load Forecast Model, and Weather Normalization and Peak Allocation.

PJM Hourly Load Data — After-the-fact hourly load data are entered by EDCs and used by PJM for deriving seasonal load profiles, weather normalization factors, 1CP zonal load contributions for Network Service billing, charts contained in the PJM Load Forecast Report, and the Monthly Operations Report.

PJM Load Forecast Model — PJM staff produces an independent forecast of monthly and seasonal peak load and load management, for each PJM zone, region, the RTO, and selected combinations of zones. The PJM Load Forecast Report includes tables and charts presenting the results.

Weather Normalization and Peak Allocation — PJM uses approved techniques for weather-normalizing historical summer and winter zonal peaks, and determining RTO unrestricted coincident peaks.

Section 2: PJM Hourly Load Data

Welcome to the *PJM Hourly Load Data* section of the ***PJM Manual for Load Forecasting and Analysis***. In this section you will find the following information:

- An overview of the historic hourly load data file (see "Load Data Overview")
- Guidelines for reporting load data to PJM (see "Load Data Reporting Business Rules")

2.1 Load Data Overview

Official historic hourly load data for each EDC with revenue-metered tie data reported to PJM are collected via the Power Meter application. For EDCs submitting all internal generation, Power Meter will calculate a revenue-quality load based on submitted tie and generation meter values. This ensures that all customer demand is counted once and only once, on an aggregated and dispersed basis. EDCs may accept these values as their reported hourly service territory load, with the option to input data directly through the application's user interface or via uploaded XML files. The entered data are available through Power Meter screens, postings on the PJM website, or in several reports produced by the Performance Compliance Department.

[For details on submitting data into Power Meter, refer to the information posted on the PJM Website (under "Tools Sign In", select "Power Meter.")]

Load Data Definitions

Actual Net Metered Interchange: The sum of allocated tie metered values to which the EDC is a party.

Total Internal Generation: The sum of all meter values for non-500kV generators electrically located in the EDC's zone. For PJM Western and Southern regions, 500kV generation will be counted as part of internal generation.

Allocated Mid-Atlantic 500kV Losses: Participant's share of total PJM Mid-Atlantic 500kV losses

Calculated Load = Actual Net Metered Interchange + Total Internal Generation + Allocated 500kV Losses.

2.2 Load Data Reporting Business Rules

As established by the PJM Planning Committee, the following guidelines govern the reporting of load data into the PJM Power Meter application:

Data Reporting Responsibility: It will be the responsibility of each PJM electric distribution company (EDC) with fully-metered tie flows to report hourly load data for its metered area(s), regardless of which entity is responsible for serving end-use customers.

For all entities using network transmission service, it will be the responsibility of the signatory to the Network Integration Transmission Service Agreement to ensure that hourly load data are reported to PJM for its customers via PJM InSchedules.

Curtailment Service Providers (CSPs) are responsible for providing information to estimate load management impacts as detailed in Attachment A.

Data Specifications: Load data supplied to Power Meter will reflect each entity's total impact to the system, counting all customer demand once and only once, and will therefore need to properly account for system losses and flows. PJM will adjust loads for their assigned share of Extra High Voltage losses. LSEs providing load management impact estimates will adjust loads for system losses. Data are accepted in Power Meter in 0.001 MWh increments.

Reporting Schedule: The data for each day should initially be entered within the following ten calendar days, except during peak periods, when the data must be entered daily. PJM contacts EDCs when daily reporting is needed.

Edits to load data should be made by the tenth calendar day of the following month.

PJM will adjust submitted load data, as necessary, to reflect additional load that is determined by PJM after-the-fact, resulting from third-party supply of generator station power requirements.

EDC ability to submit loads via Power Meter is subject to a reporting window that includes the current month and three previous months. For example, in April, values for April, March, February, and January can be freely edited. For updates to months older than three full months prior, the participant must have PJM make the submission on their behalf. PJM may be contacted at mrkt_settlement_ops@pjm.com to arrange for assistance.

Failure to report data to PJM in a timely and complete manner will subject responsible parties to Data Submission Charges, as outlined in Schedule 13 of the Reliability Assurance Agreement and the PJM West Reliability Assurance Agreement.

EDC/ CSP Actions:

- *Enter Hourly Load Data* — PJM EDCs submit aggregate hourly load values into Power Meter, as required. CSPs provide resource-specific settlements data to quantify Load Management impacts into the eLRS application. (*See Attachment A*).
- *Edit the Data as necessary* — All hourly load value changes for a given month must be entered and edited by the 10th of the following month.

- *Notify PJM of All Changes* — Without this notification, PJM can only determine that changes have been made but cannot readily identify specific changes which were made.

PJM Actions:

- *Allocate Extra High Voltage Losses:* — 500kV losses in the PJM Mid-Atlantic region are calculated as the total 500kV system energy injections minus withdrawals. Hourly 500kV losses are allocated to each PJM Mid-Atlantic EDC with revenue metered tie flows reported to Power Meter, in proportion to their real-time load ratio share.

- *Distribute Reports:* — By the 10th of each month, PJM makes reports of load data from the previous month available to the EDCs. These data include a summary Daily Load Report for each day of the month, showing daily peak loads and the monthly energy total for each LSE and for the PJM RTO. A monthly summary report also is provided.

- *Post Zonal Data:* — PJM will publish zonal load data in an electronic format on a monthly basis.

- *Data Usage:* — PJM uses the hourly load data for operational analysis, for calculating seasonal load factors, developing weather normalization curves, for allocating the PJM weather normalized seasonal peaks, and for preparing various charts and tables in the PJM Load Forecast Report, and for reporting to regulatory and other authorities.

Section 3: PJM Load Forecast Model

Welcome to the *PJM Load Forecast Model* section of the ***PJM Manual for Load Forecasting and Analysis***. In this section you will find the following information:

- An overview of the PJM Load Forecast Model (see "Forecast Model Overview").
- A description of the methodology used to produce the PJM forecast (see "Development of the Forecast").
- A description of the forecast review and approval process (see "Review and Approval the Forecast").

3.1 Forecast Model Overview

The PJM Load Forecast Model produces 15-year monthly forecasts of unrestricted peaks assuming a range of weather conditions for each PJM zone, locational deliverability area (LDA) and the RTO. The model uses trends in equipment and appliance usage, anticipated economic growth and historical weather patterns to estimate growth in peak load and energy use. It is used to set the peak loads for capacity obligations, for reliability studies, and to support the Regional Transmission Expansion Plan. Net energy forecasts are used in reporting requirements of FERC and NERC, and for market efficiency studies. The forecast is produced by PJM and released prior to each Planning Period, typically in January.

3.2 Development of the Forecast

The PJM Load Forecast employs econometric multiple regression models to estimate daily peak load for each PJM zone (the non-coincident peak), the zone's contribution to the daily RTO peak (the coincident peak), and monthly net energy for load. Definitions of each model variable are presented in Exhibit 1. The variables included are:

Dependent Variable - Load:

Hourly metered load data are supplemented with estimated load drops (as outlined in Attachment A) to obtain unrestricted hourly loads. For the non-coincident models, the maximum value for each day is used in the regressions. For the coincident models, the zone's contribution to the daily RTO/LDA unrestricted peak load is used in the regressions. For the net energy models, the sum of each day's hourly loads is used in the regressions.

Calendar Effects:

Days of the week, month of the year, holiday, and Daylight Saving Time impacts are included in the model using binary variables. Holiday seasonal lighting load is reflected using a trend variable.

Weather Data:

Weather is included in the models using different variables for heating, cooling and shoulder seasons. Weather variables are specified as splines over defined ranges. For the heating season (December, January and February), the Winter Weather Parameter is defined as:

$$\text{If } WIND > 10 \text{ mph},$$

$$WWP = DB - (0.5 * (WIND - 10))$$

$$\text{If } WIND \leq 10 \text{ mph},$$

$$WWP = DB$$

Where: WIND = Wind velocity, in miles per hour;

WWP = Wind speed adjusted dry bulb temperature;

DB = Dry bulb temperature (°F).

For the cooling season (May, June, July, August, and September), Temperature-Humidity Index (THI) is used as the weather variable:

$$\text{If } DB \geq 58,$$

$$THI = DB - 0.55 * (1 - HUM) * (DB - 58)$$

$$\text{If } DB < 58,$$

$$THI = DB$$

Where: THI = Temperature humidity index;

DB = Dry bulb temperature (°F);

HUM = Relative Humidity (where 100% = 1).

For shoulder months (March, April, October and November), a combination of wind-adjusted temperature and temperature-humidity index serves as the weather variable.

Additionally, measures of heating and cooling degree days are included, using the current and previous day's weather. Weather data for each PJM zone are calculated according to the mapping presented in Exhibit 2.

Economic Drivers:

Measures of economic and demographic activity are included in the forecast models, representing total U.S., state, or metropolitan areas, depending upon their predictive value. Economic drivers for states and metropolitan areas are assigned to each PJM zone according to the mapping presented in Exhibit 3. Models for each PJM zone share the same general specification.

End-Use Trends:

Measures of the stock and efficiency of various electrical equipment and appliances used in residential and commercial settings are included in the forecast models, grouped by heating, cooling, and other. End-use variables for each PJM zone are applied by Census Division, as presented in Exhibit 3. End-use variables are weighted by the Residential and Commercial sales of each zone, per FERC Form 1 filings.

Load Adjustments:

In cases where a zone has experienced or is anticipated to experience a significant load change that may not be captured in the load forecast, PJM may elect to apply a load forecast in one of two ways: 1) for identified changes that have not yet occurred, by an explicit adjustment to the modeled forecast; and 2) for changes that have already occurred, by the introduction of a binary variable into the affected zone's model specification.

In cases where the load change has not yet occurred, PJM will base any adjustment on information received from EDC load forecasters in response to PJM's annual request for details on large load changes that are known to the EDC. PJM will handle these requests on a case-by-case basis and perform (or have performed) whatever analysis is required to establish the degree of certainty and magnitude of the load change. Attachment C provides load forecast adjustment guidelines.

In cases where a zone has experienced a large, sudden shift in load (or following the use of a manual load adjustment in a prior forecast), a load adjustment dummy (binary) variable may be added to the zone's model specification. The resulting model coefficient must satisfy the following criteria:

- Be explained by an identifiable occurrence (such as the migration of load from another service territory, factory shutdown, or a price shock);
- Be statistically significant;
- Have a sign in the expected direction;
- Have a magnitude that is consistent with the expected load shift;
- Have a magnitude, relative to the zone's metered peak, large enough to make a discernible difference in the forecast; and
- Make an appreciable improvement to model fit statistics.

Non-Coincident Base and 90/10 Scenarios

For each PJM zone, a distribution of non-coincident peak (NCP) forecasts is produced using a Monte Carlo simulation process. Monte Carlo simulation is useful for simulating a phenomenon (in this case, electrical load) with significant uncertainty with regard to one or more of its driving influences (in this case, the weather conditions that will occur in the future). Using the Monte Carlo approach, load forecasts are developed for each zone using the actual weather patterns that were observed in that zone over many years. The simulation process produces a distribution of monthly forecast results by selecting the 12 monthly peak values per forecast year for each weather scenario. For each year, by weather scenario, the maximum daily NCP load for a zone over each season is found. For each zone and year, a distribution of zonal NCP by weather scenario is developed. From this distribution, the median values are used to shape the monthly profile within each season.

The median result is used as the base (50/50) forecast; the values at the 10th percentile and 90th percentile are assigned to the 90/10 weather bands.

RTO and Coincident Forecasts

To obtain the RTO/LDA *peak forecast, the solution for each of the zonal coincident peak* (CP) models are summed by day and weather scenario to obtain the RTO/LDA peak for the day. By weather scenario, the maximum daily RTO/LDA value for the season is found. For the RTO/LDA, a distribution of the seasonal RTO/LDA peak vs. weather scenario is developed. From this distribution, the median result is used as the base (50/50) forecast; the values at the 10th percentile and 90th percentile are assigned to the 90/10 weather bands.

To determine the final zonal RTO/LDA -coincident peak (CP) forecasts, a methodology similar to the process for deriving zonal NCPs is applied. By weather scenario, the maximum daily CP load for a zone over the summer season is found. For each zone a distribution of zonal CP vs. weather scenario is developed. From this distribution the median value is selected. The median zonal CPs are summed and this sum is then used to apportion the forecasted RTO/LDA peak to produce the final zonal CP forecasts.

Net Energy for Load Forecasts

For each PJM zone, a distribution of forecasts is produced using a Monte Carlo simulation process. The weather distributions are developed using observed historical weather data. The simulation process produces a distribution of monthly forecast results by summing the daily values per forecast year for each weather scenario.

Load Management, Energy Efficiency, Price Responsive Demand and Behind-the-Meter Generation

PJM incorporates assumptions of load management, energy efficiency, price responsive demand and behind-the-meter generation to supplement the base, unrestricted forecast.

For Demand Resources (DR), forecasted values for each zone are computed based on the following procedure. The forecast is based on the PJM final summer season Committed DR amount, where the Committed DR means all DR that has committed through RPM, Base Residual Auction and all Incremental Auctions, or a Fixed Resource Requirement plan.

1. Compute the final amount of Committed DR for each of the most recent three Delivery Years. Express the Committed DR amount as a percentage of the zone's 50/50 forecast summer peak from the January Load Forecast Report immediately preceding the respective Delivery Year.

2. Compute the most recent three year average Committed DR percentage for each zone.

3. The DR forecast for each zone shall be equal to the zone's 50/50 forecast summer peak multiplied by the result from Step 2.

The impact of price responsive demand equals the amount subscribed through the RPM process. The amount subscribed for the last RPM auction year is held constant for the remainder of the forecast.

[Note: More information on behind-the-meter generation can be found in the Behind-the-Meter Generation Business Rules in the PJM Manual for Generator Operational Requirements (M-14D) posted on PJM.com.]

3.3 Non-Zone Peak Forecast

For use in the Reliability Pricing Model (RPM), PJM staff develops summer peak forecasts of the recognized non-zone loads. These forecasts are produced separately from the PJM Load Forecast Model, and utilize methods appropriate for each situation. Non-zone forecasted loads are added to the associated PJM zone for RPM purposes only.

3.4 Review of the Forecast

The PJM Load Forecast is reviewed by the Load Analysis Subcommittee and the Planning Committee.

A member of the Planning Committee may submit an appeal (detailing the issue and outlining a solution) for a review of part or all of the forecast, which will be forwarded by the Chair of the Planning Committee to PJM, upon a vote of the Committee.

Calendar Data

Day of week

Variable Name	Type/ Formula	Description
Monday	Binary	Day of the Week
Tuesday	Binary	Day of the Week
Wednesday	Binary	Day of the Week
Thursday	Binary	Day of the Week
Friday	Binary	Day of the Week
Saturday	Binary	Day of the Week

Holiday

MartinLutherKingDay	Fuzzy	MLK Day Holiday
PresidentsDay	Fuzzy	President's Day Holiday
GoodFriday	Binary	Good Friday Religious Holiday
MemorialDay	Fuzzy	Memorial Day Holiday
July4th	Fuzzy	Independence Day and surrounding days
LaborDay	Fuzzy	Labor Day Holiday
Thanksgiving	Binary	Thanksgiving Holiday
FridayAfterThanksgiving	Fuzzy	Friday After Thanksgiving Holiday
XMasWkB4	Fuzzy	Week Before Christmas
ChristmasEve	Fuzzy	Christmas Eve (value depends on day of week)
ChristmasDay	Binary	Christmas Day
XMasWk	Fuzzy	Week after Christmas Holiday
NewYearsEve	Fuzzy	New Years Eve(value depends on day of week)
NewYearsDay	Binary	New Years Day Holiday
XMasLights	Trend	Christmas Lights/Retail Operations Trend

Month

January	Binary	Month of the Year
February	Binary	Month of the Year
March	Binary	Month of the Year
April	Binary	Month of the Year
May	Binary	Month of the Year
June	Binary	Month of the Year
July	Binary	Month of the Year
August	Binary	Month of the Year
September	Binary	Month of the Year
October	Binary	Month of the Year
November	Binary	Month of the Year

Other

DLSav_EPA2005	Binary	Daylight Saving Time conversion

Notes:
Binary – A variable which has a value of 1 for the indicated characteristic, otherwise the value is 0.
Fuzzy – A variable which has a conditional value for the indicated characteristic, otherwise the value is 0.
Trend - A variable which has a value with increasing then decreasing value for the indicated characteristic, otherwise the value is 0.

End-Use/ Weather Variables

S1_THI	IF (month ≥ 5 & month ≤ 9) AND MaxTHI ≤ Spline2 Threshold THEN MaxTHI[1] ELSE 0
Cool_S2_THI	IF (month ≥ 5 & month ≤ 9) AND Spline2 Threshold < MaxTHI ≤ Spline3 Threshold THEN Cool * (MaxTHI – Spline2 Threshold) ELSE 0
Cool_S3_THI	IF (month ≥ 5 & month ≤ 9) AND Spline3 Threshold < MaxTHI ≤ Spline4 Threshold THEN Cool * (MaxTHI – Spline3 Threshold) ELSE 0
Cool_S4_THI	IF (month ≥ 5 & month ≤ 9) AND MaxTHI > Spline4 Threshold THEN Cool * (MaxTHI – Spline4 Threshold) ELSE 0

Cool = (Residential Equipment Index * (R/(R+C)) * (Commercial Equipment Index * (C/(R+C))

Where,

R=Residential sector electricity sales

C=Commercial sector electricity sales

Residential Equipment Index = $\Sigma_{u=1\text{-}n,\ y=1998\text{-}yr}$ (Saturation$_{u,y}$/Efficiency$_{u,y}$)/ (Saturation$_{u,1998}$/Efficiency$_{u,1998}$)

Commercial Equipment Index = $\Sigma_{u=1\text{-}n,\ y=1998\text{-}yr}$ (Saturation$_{u,y}$/Efficiency$_{u,y}$)/ (Saturation$_{u,1998}$/Efficiency$_{u,1998}$)

U= Equipment type

Y=year

Intermediate Calculations:

1 MaxTHI Maximum THI over 24 hours

Heat_S1_WWP	IF (month ≤ 2 or month = 12) AND WWP_HR19 ≥ Spline2 Threshold THEN Heat * WWP_HR19^2 ELSE 0
Heat_S2_WWP	IF (month ≤ 2 or month = 12) AND Spline3 Threshold ≤ WWP_HR19 < Spline2 Threshold THEN Heat * (WWP_HR19 - Spline2 Threshold) ELSE 0
Heat_S3_WWP	IF (month ≤ 2 or month = 12) AND Spline4 Threshold ≤ WWP_HR19 < Spline3 Threshold THEN Heat * (WWP_HR19 – Spline3 Threshold) ELSE 0
Heat_S4_WWP	IF (month ≤ 2 or month = 12) AND WWP_HR19 < Spline4 Threshold THEN Heat * (WWP_HR19 – Spline4 Threshold) ELSE 0

Heat = (Residential Equipment Index * (R/(R+C)) * (Commercial Equipment Index * (C/(R+C))

Heat_Shldr_50LT	IF (month = 3 or month = 4 or month = 10 or month = 11) THEN
	IF (WWP_HR19 < 50) THEN
	Heat * WWP_HR19
	ELSE 0

Shldr_BASE	IF (month = 3 or month = 4 or month = 10 or month = 11) THEN
	IF (WWP_HR19 >= 50 and WWP_HR19 <= 70) THEN
	Heat * WWP_HR19 - 50
	ELSE 0

Cool_Shldr_THI	IF (month = 3 or month = 4 or month = 10 or month = 11) THEN
	IF (Heat_Shldr_50LT = 0 and Shldr_BASE = 0) THEN
	Cool * MaxTHI
	ELSE 0

End-Use/Economic/Weather Data

Variable Name	Formula	Description
Cool_IN2_CDD	Cool*DailyEconIndex*CDD	Cooling equipment index interacted with degree days and economic index

2 WWP_HR19 WWP for hour ending 19:00

Cool_IN2_LAG1CDD Cool *DailyEconIndex *CDD_LAG[3] Cooling equipment index Interacted with lagged degree days and economic index

Heat_IN2_HDD Heat *DailyEconIndex *HDD Heating equipment index interacted with degree days and economic index

Heat_IN2_LAG1 HDD Heat*DailyEconIndex*HDD_LAG[4] Heating equipment index interacted with lagged degree days and economic index

End-Use/Economic Data

Other_IN2 Other * DailyEconIndex Other equipment index interacted with economic index

Other = (Residential Equipment Index * (R/(R+C)) * (Commercial Equipment Index * (C/(R+C))

3 CDD_LAG Cooling degree days from prior day
4 HDD_LAG Heating degree days from prior day

Economic Data

Variable Name	Description
DailyEconIndex	Economic index quarterly values converted to daily

$$EconIndex = ResWt \times (HH_{y,m}/HH_{base})^{0.47} \times (Pop_{y,m}/Pop_{base})^{0.26} \times (PInc_{y,m}/PInc_{base})^{0.27}$$
$$+ ComWt \times (NMEmp_{y,m}/NMEmp_{base})^{0.47} \times (GDP_{y,m}/GDP_{base})^{0.20} \times (GMP_{y,m}/GMP_{base})^{0.16} \times (Pop_{y,m}/Pop_{base})^{0.17}$$
$$+ IndWt \times (GDP_{y,m}/GDP_{base})^{0.47} \times (GMP_{y,m}/GMP_{base})^{0.53}$$

Where: ResWt is the residential sector sales percentage to total zonal electric sales in year (y);
HH is the number of households in year (y) and month (m);
Pop is the population in year (y) and month (m);
PInc is the value of total real personal income in year (y) and month (m);
ComWt is the commercial sector sales percentage to total zonal electric sales in year (y);
NMEmp is the number of non-manufacturing employees in the metro area(s) in year (y) and month (m);
GDP is the value of total real gross domestic product in the United States in year (y) and month (m);
GMP is the value of total real gross metropolitan product in the metro area(s) in year (y) and month (m);
IndWt is industrial sector sales percentage to total zonal electric sales in year (y);
And base indexes the base year.

Load Adjustment

LA_<yy>	Binary	Adjustment for year 20yy forward

Exhibit 1: Model Variable Definitions

Zone	Weather Station	Airport Name	Weight
AE	ACY	Atlantic City International	1
AEP	CAK	Akron-Canton Regional Airport	0.151
AEP	CMH	Columbus Port Columbus International	0.234
AEP	CRW	Charleston Yeager Airport	0.226
AEP	FWA	Fort Wayne International Airport	0.227
AEP	ROA	Roanoke Regional Airport	0.162
APS	IAD	Washington Dulles	0.3
APS	PIT	Pittsburgh International	0.7
ATSI	CAK	Akron-Canton Regional Airport	0.465
ATSI	CLE	Cleveland Hopkins Airport	0.3
ATSI	TOL	Toledo Express Airport	0.15
ATSI	PIT	Pittsburgh International Airport	0.085
BGE	BWI	Baltimore Washington International	1
COMED	ORD	Chicago O'Hare International	1
DAY	DAY	Cox-Dayton International	1
DEOK	CVG	Cincinnati Northern KY Airport	1
DLCO	PIT	Pittsburgh International	1
DOM	IAD	Washington Dulles	0.3333
DOM	ORF	Norfolk International	0.3333
DOM	RIC	Richmond International	0.3334
DPL	ILG	Wilmington New Castle County Airport	0.7
DPL	WAL	Wallops Island Flight Center	0.3
EKPC	CVG	Cincinnati Northern KY Airport	0.25
EKPC	LEX	Blue Grass Airport	0.49
EKPC	SDF	Louisville International Airport	0.26
JCPL	EWR	Newark International	0.75
JCPL	ACY	Atlantic City International	0.25
METED	PHL	Philadelphia International	0.5
METED	ABE	Allentown Lehigh Valley International	0.5
PECO	PHL	Philadelphia International	1
PENLC	ERI	Erie International	0.5
PENLC	IPT	Williamsport Regional	0.5
PEPCO	DCA	Washington Reagan National	1
PL	ABE	Allentown Lehigh Valley International	0.25
PL	AVP	Wilkes-Barre Scranton International	0.25
PL	IPT	Williamsport Regional	0.25
PL	MDT	Harrisburg International	0.25
PS	EWR	Newark International	1
RECO	EWR	Newark International	1
UGI	AVP	Wilkes-Barre Scranton International	1

Exhibit 2: Assignment of Weather Stations to Zones

Zone	State(s)	Metro Area Name(s)	Census Division
AE	NJ	Atlantic City-Hammonton NJ, Ocean City NJ, Vineland-Bridgeton NJ	Middle Atlantic
AEP	OH, WV, VA, IN	Elkhart-Goshen IN, Fort Wayne IN, Muncie IN, South Bend-Mishawaka IN-MI, Niles-Benton Harbor MI, Canton-Massillon OH, Columbus OH, Lima OH, Kingsport-Bristol TN, Blacksburg-Christiansburg-Radford, VA, Lynchburg VA, Roanoke VA, Beckley, WV, Charleston WV, Huntington-Ashland WV-KY-OH, Weirton-Steubenville WV-OH	East North Central
APS	PA, OH, WV	Cumberland MD-WV, Hagerstown-Martinsburg MD-WV, Chambersburg-Waynesboro PA, State College PA, Winchester VA-WV, Morgantown WV, Parkersburg-Vienna WV	South Atlantic
ATSI	PA, OH	Akron OH, Cleveland-Elyria OH, Mansfield OH, Springfield OH, Toledo OH, Youngstown-Warren-Boardman OH-PA, Pittsburgh PA	East North Central
BGE	MD	Baltimore-Columbia-Towson MD	South Atlantic
COMED	IL	Chicago-Naperville-Arlington Heights IL, Elgin IL, Kankakee IL, Lake County-Kenosha County IL-WI, Rockford IL	East North Central
DAY	OH	Dayton OH	East North Central
DEOK	OH	Cincinnati OH-KY-IN	East North Central
DLCO	PA	Pittsburgh PA	Middle Atlantic
DOM	VA	Charlottesville VA, Harrisonburg VA, Richmond VA, Roanoke VA, Staunton-Waynesboro VA, Virginia Beach-Norfolk-Newport News VA,	South Atlantic
DPL	DE	Dover DE, Wilmington DE-MD-NJ, Salisbury MD-DE	South Atlantic
EKPC	KY	Cincinnati OH-KY-IN, Louisville/Jefferson County KY-IN, Elizabethtown-Fort Knox KY, Bowling Green KY, Lexington-Fayette KY, Huntington-Ashland WV-KY-OH	East South Central
JCPL	NJ	Camden NJ, Newark NJ-PA, Trenton NJ	Middle Atlantic
METED	PA	Allentown-Bethlehem-Easton PA-NJ, East Stroudsburg PA, Gettysburg PA, Lebanon PA, Reading PA, York-Hanover PA,	Middle Atlantic
PECO	PA	Montgomery County-Bucks County-Chester County PA, Philadelphia PA	Middle Atlantic
PENLC	PA	Altoona PA, Erie PA, Johnstown PA	Middle Atlantic
PEPCO	MD	Washington D.C., California-Lexington Park MD	South Atlantic
PL	PA	Allentown-Bethlehem-Easton PA, Bloomsburg-Berwick PA, East Stroudsburg PA, Harrisburg-Carlisle PA, Lancaster PA, Scranton-Wilkes-Barre-Hazleton PA, Williamsport PA	Middle Atlantic
PS	NJ	Camden NJ, Newark NJ-PA, Trenton NJ	Middle Atlantic

RECO	NJ	Newark NJ-PA	Middle Atlantic
UGI	PA	Scranton-Wilkes-Barre-Hazleton PA	Middle Atlantic

Exhibit 3: Assignment of Metropolitan Areas, Census Divisions and States to Zones

Section 4: Weather Normalization and Coincident Peaks

Welcome to the *Weather Normalization and Coincident Peaks* section of the ***PJM Manual for Load Forecasting and Analysis***. In this section you will find the following information:

- An overview of the weather normalization process (see "Weather Normalization Overview").
- A description of the weather normalization procedure (see "Weather Normalization Procedure").
- A description of the identification and calculation of PJM unrestricted coincident peaks (see "Peak Load Allocation (5CP)").

4.1 Weather Normalization Overview

PJM performs load studies on summer and winter loads, for both coincident and non-coincident peaks, according to the procedures described below. The weather normalized (W/N) coincident peaks are used by EDCs to determine capacity peak load shares for wholesale and retail customers. W/N non-coincident peaks are provided by PJM for use by stakeholders in reviewing the PJM load forecast.

4.2 Weather Normalization Procedure

For non-coincident weather-normalized seasonal peaks, daily zonal peak loads on non-holiday weekdays for a three-year period (the study year and two prior years) are regressed against a seasonal weather variable. The seasonal weather variables are those used in the load forecast model (as described in Section 3.2). Regressions only include days in the heating/cooling range (summer > 74 WTHI, winter < 45 WWP). A binary adjustment is applied for each of the two earlier years, to allow for load growth. The resulting regression equation is solved at each zone's weather standard, which is the average of the extreme seasonal weather variable values on non-holiday weekdays for a period consistent with the load forecast.

To determine coincident zonal weather-normalized seasonal peaks, the results of the non-coincident process described above are adjusted by each zone's average annual diversity to the PJM RTO seasonal peak over available history. The zonal values are summed to determine the PJM RTO seasonal weather-normalized peak.

EDC/ CSP Actions:

- Enter hourly load data into Power Meter as described in Section 2 of this manual.
- Provide resource-specific settlements data to quantify Load Management impacts into the eLRS application
- Submit voltage reduction and loss of Load Drop Estimates as described in Attachment A of this manual.

- Participate in review of seasonal load studies, through the Load Analysis Subcommittee.

PJM Actions:

- Obtain weather observations
- Produce voltage reduction load drop estimates, as described in Attachment A of this manual.
- Weather-normalize the zonal RTO-coincident winter and summer peak loads.

4.3 Peak Load Allocation (5CP)

Zonal weather-normalized RTO-coincident summer peak loads are allocated to the wholesale and retail customers in the zones using EDC-specific methodologies that typically employ the customer's shares of RTO actual peaks. The resulting Peak Load Contributions are then used in the determination of capacity obligations.

PJM establishes and publishes information, referred to as the 5CP, to aid EDCs in the calculation of Peak Load Contributions (also known as "tickets"). For each summer:

- Hourly metered load and load drop estimate data are gathered for the period June 1 through September 30
- RTO unrestricted loads are created by adding load drop estimates to metered load
- From the unrestricted values, the five highest non-holiday weekday RTO unrestricted daily peaks (5CP) are identified

5CP data are typically released in mid-October.

Attachment A: Load Drop Estimate Guidelines

General

Load Drop Estimates (also referred to as addbacks) are produced for three types of occurrences:

1. Curtailment of load for customers registered in the PJM emergency or pre-emergency program either as a Load Management resource (Demand Resource) or an Emergency – Energy Only resource, or customers registered to meet a Price Responsive Demand (PRD) commitment for either the Reliability Pricing Model (RPM) or the FRR Alternative.

2. Voltage Reductions implemented by PJM or an EDC

3. Significant losses of load.

PJM is responsible for producing Load Management/Emergency/Pre-Emergency load drop estimates, from CSP and EDC input into the appropriate PJM system. EDCs are responsible for reporting the estimated impact of voltage reductions (optional) or significant losses of load on their systems.

PJM is responsible for producing PRD load drop estimates, from PRD Provider input into the appropriate PJM system. For purposes of 5CP identification, PRD Providers that registered price responsive demand to satisfy a PRD commitment for either RPM or FRR Alternative must provide PJM with meter data for a set of high load days to be identified by PJM by the end of each September. Meter data is entered at the site level; load drop estimates will be calculated at the registration level. Load drop estimates will only be applied for Maximum Emergency Generation hours as well as for any 5CP hours when there was no Maximum Emergency Generation event.

Load drop estimates are used to construct unrestricted loads used in the PJM Load Forecast Model, weather normalization of PJM seasonal peaks, and to calculate the unrestricted Peak Load Contributions used in formulating capacity obligations.

These rules also apply to Non-Retail Behind-the-Meter Generation as provided in Section G of Schedule 6 to the Reliability Assurance Agreement.

Load Drop Estimates for Load Management Customers

The table below summarizes the requirements for producing load drop estimates for customers registered as a Demand Resource, or in the Emergency– Energy Only option, or as Economic load response, depending upon the cause of the load curtailment. Following the table are descriptions of the methods used by PJM to calculate load drop estimates for each load management type (Legacy Direct Load Control, Firm Service Level, and Guaranteed Load Drop).

Requirements for Production of Load Drop Estimates

Reason for Load Drop		*PJM-Initiated Emergency or Pre-Emergency or CSP-Initiated Test*	*Economic*	*EDC- or CSP-Initiated*
Program Registration	*Emergency/Pre-Emergency Full (DR) or Emergency/Pre-Emergency Capacity Only (DR)*	*Load Drop Estimates must be produced for any interruptions from June 1 through September 30.*	*Load Drop Estimates must be produced for any settled interruptions from June 1 through September 30.*	*No Load Drop Estimates required.*
	Emergency Energy Only	*Load Drop Estimates must be produced for any interruptions during Emergency/Pre-Emergency hours from June 1 through September 30.*	*No Load Drop Estimates required.*	*No Load Drop Estimates required.*
	Economic	*No Load Drop Estimates required.*	*No Load Drop Estimates required.*	*No Load Drop Estimates required.*

Actual Emergency and Pre-Emergency Load Response and Economic Load Response load reductions for Load Management resources registered as Emergency Full or Emergency Capacity Only resources which occur from June 1 through September 30, will be added back for the purpose of calculating peak load for capacity for the following Delivery Year and consistent with the load response recognized for capacity compliance as set forth in the Manual.

Non-Interval Metered Customers Including Legacy Direct Load Control

Prior to June 1, 2016: the nominated quantity (MW) of Load Management provided by non-interval metered customers * Loss Factor will be the estimated load drop added back to the zone for a load management emergency, pre-emergency or test event. If the resource participates as an economic resource, then the hourly MW settled under the economic program will be used for the load drop that is added back to the zone. Non-interval metered customers may not participate in Load Management under Legacy Direct Load Control (LDLC) after May 31, 2016

Contractually Interruptible

The estimated load drop for Firm Service Level and Guaranteed Load Drop customers is calculated as follows unless it is for DR Capacity Performance, Base or Economic resource for non-summer period (October 1 through May 31 of following year). Non-summer capacity performance will be determined for such resources and time period based on the economic CBL as described in Manual 11, section 10.:

For Guaranteed Load Drop end-use customers, the lesser of (a) comparison load used to best represent what the load would have been if PJM did not declare a Load Management event or the CSP did not initiate a test as outlined in the PJM Manuals, minus the metered load ("Load") and then multiplied by the loss factor ("LF") or (b) the current Delivery Year peak load contribution ("PLC") minus the metered load multiplied by the loss factor ("LF"). A load reduction will only be recognized for capacity compliance if the metered load multiplied by the loss factor is less than the current Delivery Year peak load contribution. The calculation is represented by:

Minimum of {(comparison load – Load) * LF, PLC – (Load * LF)}

For Firm Service Level end-use customers the current Delivery Year peak load contribution ("PLC") minus the metered load ("Load") multiplied by the loss factor ("LF"). The calculation is represented by:

PLC – (Load * LF)

Note: When Generation interval meter data is provided to determine test or event compliance, and interval metering on load is available, the interval metered load data should be provided to ensure load drop is below the PLC. It is expected that interval load data will be available for all customers that have a PLC > 0.5 MW. If no interval meter load data exists, such Generation interval meter data multiplied by loss factor will be used as the estimated load drop.

Event Compliance for Guaranteed Load Drop (GLD) Customers

For purposes of determining compliance with a PJM-initiated Load Management event or test for Guaranteed Load Drop customers, several options are available to estimate comparison loads. The method used should result in the best possible estimate of what load level would have occurred in the absence of an emergency, pre-emergency or test event.

The CSP will be responsible for supplying all necessary load data to PJM in order to calculate the load reduction for each registered end use customer. PJM will calculate the load drop amount unless otherwise indicated below or approved by PJM. The amount of load data required will depend on the GLD method selected where the minimum amount shall be 24 hours for one full calendar day.

Comparable Day: The customer's actual hourly loads on one of the prior 10 calendar days before the test or emergency or pre-emergency event day selected by the CSP which best represents what the load level would have been absent the emergency or pre-emergency or test event. The CSP may request use of an alternative day for extenuating circumstances with supporting documentation that clarifies why the alternative day should be utilized. PJM must approve the use of any alternative day. CSP must provide usage data for all 10 days such that PJM may validate an appropriate day was selected.

Same Day (Before/After Event): The customer's average hourly integrated consumption for two full hours prior to notification of an emergency or pre-emergency event or prior to one full hour before a test and for two full hours after skipping first full hour after the event or test. This option is appropriate for high load factor customers with no weather sensitivity.

Customer Baseline: The Customer's estimated baseline used to calculate load drops for PJM economic demand resources as defined on the applicable PJM economic registration.

Regression Analysis: The customer's estimated hourly loads from a regression analysis of the customer's actual loads versus weather. This option is appropriate for customers with significant weather sensitivity. The CSP will perform the regression analysis and provide results including supporting information to PJM. The information should include all load and weather data and associated regression statistics used to estimate the load impact on the event or test day.

Generation: The hourly integrated output from a generator used to provide Guaranteed Load Drop. This method may only be utilized if the generation would not have otherwise been deployed on the emergency or pre-emergency event or test day and must comply with the provisions contained in the PJM Manuals.

Load Drop Estimates for PRD Customers

Load Drop Estimates are applicable to price responsive demand registrations that are used to satisfy a PRD commitment for either RPM or FRR Alternative. Load Drop Estimates are not applicable to Energy Only PRD registrations.

For Maximum Emergency Generation hour or a 5CP hour without Maximum Emergency Generation:

*Load Drop Estimate = Customer Expected Peak Load – (Metered Load * EDC Loss Factor)*

*Where: Expected Peak Load = PLC * Final Zonal Peak Load Forecast*$_{DY}$*/ Zonal Weather Normalized Peak*$_{DY-1}$*;*

PLC = Peak Load Contribution for the registration;

DY = Delivery Year

Missing Data

If an end use customer meter malfunctions during a Load Management test, retest or emergency or pre-emergency event and the end use customer performed the required load reduction activity and no interval meter data is available to use for purposes of measuring capacity compliance or to determine applicable energy settlements, then PJM may allow CSP one of the following two remedies, otherwise the end use customer will be considered to have taken no load reduction actions during such period:

1. CSP may provide supporting information to quantify the load reduction amount which includes an engineering analysis or meter data from a comparable site that reduced load based on the same actions during a comparable time, or;

2. CSP may perform a separate test for the end use customer(s) to quantify the load reduction that will be used for the test, retest or event time period compliance and, as appropriate, energy settlement(s). The test will need to be performed at comparable time and conditions to when the test, retest or emergency or pre-emergency event occurred.

Remedies will only be considered if the CSP and associated metering entity followed Good Utility Practice as outlined in the OATT, no interval load data is available from the EDC, and the CSP can provide supporting information, such as building automation system logs, to verify the load reduction action was taken during the test, or retest or emergency or pre-emergency event when the meter malfunctioned. CSP must also provide evidence that the meter did malfunction.

PJM must approve any remedy and CSP must meet appropriate load data submission deadline.

Voltage Reduction

Whenever a part of the PJM system experiences a voltage reduction, whether it is PJM- or locally initiated, the distribution companies involved are to estimate its impact on hourly load levels. The estimated impact of a 5% voltage reduction will be 1.7% of the load in the affected area at the time of the voltage reduction. Variances from this guideline are acceptable in cases where a thorough analysis was performed. In such cases, a written explanation of the estimate must accompany the reported values.

Loss of Load

Whenever a part of the PJM system experiences a loss of load event (beyond the level of nominal localized outages), the Distribution Company involved is to estimate its impact on hourly load levels. The method used to estimate the impact of the loss of load event will vary by the circumstances involved, but the outcome of the estimation should represent the best approximation of the actual hourly loads that would have occurred if the loss of load event had not occurred. A written explanation of the loss of load event and how its impact was estimated is to accompany the report.

Attachment B: Legacy Direct Load Control Load Research Guidelines

These guidelines are in effect prior to June 1, 2016 only.

The intention of these guidelines is to ensure that the estimated per-participant impacts of Legacy Direct Load Control program reliably represent the amount of load shed, on average, for active program participants.

Curtailment Service Providers with Legacy Direct Load Control programs which employ a radio signal may elect to either submit a load research study supporting base per-participant impacts for their program, or utilize the base per-participant impacts contained in the "Deemed Savings Estimates for Legacy Air Conditioning and Water Heating Direct Load Control Programs in PJM Region" report (http://www.pjm.com/~/media/documents/reports/20070406-deemed-savings-report-ac-heat.ashx). Providers utilizing other technology must submit a load research study. All Providers must submit switch operability studies once every five years.

Requirements for Provider-Submitted Studies

Study Design

DLC load research base per-participant impact studies will be designed to achieve a minimum accuracy of 90% Confidence with 20% error.

Study Detail

Load research studies submitted must present estimated per-participant impacts in a matrix which details average impacts on non-holiday weekdays by hour, for the hours ending 13:00 through 20:00 (PJM Eastern Region) or 8:00 through 21:00 (PJM Western Region), and by weather condition (over a range of local conditions under which it can reasonably be expected that the program will be implemented). Separate matrices must be estimated:

By program (and/or cycling scheme);

By PJM zone.

Switch Operability Rate

In addition to base per-participant impacts, studies submitted to PJM must also include the average switch operability rate, reflecting the percentage of all active switches which both receive the control signal and operate. The switch operability rate must be supplied with the original base impact study, and then updated every five years. Any Provider with a switch operability study older than five years will be given a switch operability rate of 50%. See below for full requirements for switch operability studies.

Utilizing the Deemed Savings Estimates

[Note: The "Deemed Savings Estimates" study report is available on the PJM.com website.]

Eligibility

Load Management Providers with Legacy Direct Load Control programs which employ a radio signal may elect to utilize the base per-participant impacts contained in the "Deemed Savings Estimates for Legacy Air Conditioning and Water Heating Direct Load Control Programs in PJM Region" report.

Base Impact Value

Base impacts for air conditioning programs will be established utilizing the aggregate values detailed in Appendix F of the Deemed Savings Estimates report. The Provider must supply the applicable duty cycle strategy (percentage of each hour the unit is interrupted) and an appropriate weather station or mix of weather stations. PJM will determine the WTHI standard value from average historical peak load weather conditions (coincident with the RTO peak). The Provider may opt to customize the base impact by supplying a research study which stratifies its program by A/C usage or connected A/C load. In this case, base impacts will be drawn from the aggregate results presented in Appendix G or H, as appropriate.

Base impacts for water heating programs will be established utilizing the aggregate values detailed in Appendix J. The Provider must supply an appropriate weather station or mix of weather stations. PJM will determine the WTHI standard value from average historical peak load weather conditions (coincident with the RTO peak)

EDCs with base impacts presented in the Deemed Savings report (BGE, JCPL, and PSEG) may elect to use those impacts.

Switch Operability Rate

1. A random sample of customers must be selected to test. The sample must meet the following requirements:

    a. The study must be designed for a minimum accuracy of 90% confidence, 10% error.

    b. The sample must be randomly selected from the entire population of customers who will be counted for load reduction. No customers can be excluded and there can be no restrictions (e.g. only selecting customers within certain zip codes, only selecting customers with certain meters, only selecting customers that have enrolled in the last 12 months, etc.).

    c. The sample must be stratified by equipment type if using multiple types of equipment to receive the signal and control the device.

   d. The sample may be stratified by program segmentation (e.g. cycling level).

2. The following must be tested/verified at each customer in the sample:

   a. The switching device needs to be properly installed, wired, etc.

   b. A signal needs to be sent to the device to cycle it. Verification that the device receives this signal must be obtained. The signal must be sent in the same manner it would be sent during an event (i.e. over a public paging system, not from a local handheld device).

   c. If the test in (2.b) does not provide verification of switch operation (i.e., it only tests signal reception), a technician must verify that the switch cycles the unit when the signal is received. This signal does not need to be sent in the same manner as it would during the event – it can be sent from a local handheld device.

   d. If (2.a), (2.b) and (2.c) do not determine that the unit can properly receive the signal and control the device, the device is counted as inoperable. A technician may fix inoperable switches, however the device must still be counted as inoperable for the study.

3. Any Provider with a switch operability study older than five years will be given a switch operability rate of 50%

Attachment C: Load Forecast Adjustment Guidelines

The intention of these guidelines is to ensure that any adjustments made to PJM's load forecast model are properly identified, estimated, and reviewed prior to incorporation into the forecast.

Issue Identification

- PJM annually solicits information from its member Electric Distribution Companies (EDC) for large load shifts (either positive or negative) which are known to the EDC but may be unknown to PJM. PJM will send the request in mid-July with responses expected in time for any proposed adjustments to be reviewed with the Load Analysis Subcommittee in October/November.
- Any other load changes which are brought to PJM's attention.

Issue Verification – verify that identified issue is real and significant, using the following methods:

- Determine if the load change has been publically acknowledged through the media, press release, regulatory process, etc.
- Verify that requesting EDC has adjusted its own financial/planning forecast
- Ascertain that the load shift is related to a single site or a limited number of related sites (not a systemic cause)
- Discuss with economic forecast vendor(s) whether or not the load shift is reflected in its/their economic forecast(s). Also, determine if the requested load adjustment's load impact is consistent with its economic impact. Additionally, determine if the requested load adjustment is tied to any of the metro areas that PJM uses to define the economic variable of a zone.
- Verify that any behind-the-meter generation adjustment has complied with PJM's behind-the-meter process
- Determine adjustment's significance, either by sheer magnitude or percentage of a zone's load.

Adjustment Estimation- for each identified and verified issue, estimate its impact on peak load using the following methods (which may be combined):

- Acquire load history for the load that has/will change and produce analysis to isolate the impact (e.g., forecast runs with and without the load involved, trend analysis)
- Acquire any contracted amounts of load changes
- For any after-the-fact adjustments, review the zone's forecast model's residual pattern
- Review any available independent analysis of the impact of the load change.

Adjustment Review – Each proposed load forecast adjustment will be reviewed with the Load Analysis Subcommittee prior to inclusion in the load forecast. The final decision on any load adjustment is made by PJM.

Example 1: Loss of a Single Industrial Load

Issue Identification – In response to PJM's annual solicitation for information regarding large load shifts, a member EDC notified PJM that it was losing a large industrial load, which was a plant scheduled to shut down in a few months (and prior to the release of the next load forecast)

Issue Verification – PJM reviewed the EDC's request and through conference calls, e-mail exchanges, an EDC-provided case statement, and PJM independent investigation it was determined that:

- The plant closing was widely reported in local media as well as by a press release from the end-use customer;
- The EDC had adjusted its own financial and planning forecasts to reflect a closure at the plant;
- The affected load was confined to one site/customer account.
- The customer's peak load was approximately 500 MW.

Additionally, PJM consulted with its economic forecast supplier and determined that the forecasts of metropolitan areas within the affected zone were not adjusted to reflect the plant closure. Based on these findings, PJM concluded that the load shift was factual and material.

Adjustment Estimation – PJM requested and received historical load data for the end-use customer. An attempt was made to separately model the zone's peak load without the customer's load in order to draw a comparison to the forecast of the zone's full load. While the model produced a reasonable result for the first forecast year (-370MW), the difference quickly shrank and eventually became negative. As an alternative, the average daily peak over the model's estimation was computed. This value (-369 MW) was essentially equal to the difference between the two models in the first forecast years. PJM notified the EDC and members that the zone's load forecast would be lowered by 370MW.

Example 2: Accelerating Load

Issue Identification – A member EDC proactively notified PJM that it was in the early stages of preparing to integrate a large amount of accelerating load associated with one industry through 2023 and requested a face-to-face meeting to discuss the issue.

Issue Verification – PJM met with the EDC and through follow-up conference calls, e-mail exchanges and PJM independent investigation it was determined that:

- The load in question was associated with greenfield construction and was confined to a cluster of sites in one small area of the zone.

- The EDC had adjusted its own financial and planning forecasts to reflect the increased load;
- The new load sites have the characteristic of an extremely low number of employees per site, and therefore have a peak load impact out of proportion to their economic impact.
- Expected growth in the next three years was already underway and contracts with the EDC, construction companies, and suppliers were in place.

PJM consulted with its economic forecast supplier to verify the claim that the new load would involve very little employment increases or other economic impact and that the forecasts of metropolitan areas within the affected zone were not adjusted to reflect the activity associated with expected construction and on-going business. Based on these findings, PJM concluded that the matter merited further review.

Adjustment Estimation – The requesting EDC provided PJM with a third-party consultant's report analyzing the expected load expansion. The report detailed how the electric load in the industry had expanded within the EDC zone and how the consultants had extrapolated that growth to estimate the amount of peak load already incorporated into the PJM load forecast. Separately, a set of four forecast scenarios were generated to estimate the total industry load in the zone's subarea, representing 1) continuation of the historical trend established in the area; 2) continuation of growth at a reduction of 15% from the historical trend established in the area; 3) continuation of growth at the average industry expectation; and 4) continuation of growth at a 45% reduction in historical trends. The estimated amount of peak load already contained in the PJM forecast was netted from each scenario forecast to derive the amount of load growth not captured in the PJM forecast.

PJM was given access to the consultants who prepared the report, and through phone and e-mail reviewed the report and supplied questions to the consultants. PJM requested and received the detailed data used to generate the report's analysis and replicated it. PJM staff then reviewed the report and forecasts with PJM management. It was decided that the scenario based on the 15% reduction from the historical trend was most likely and it was used as adjustments to the PJM forecast.

Attachment D: Residential Non-Interval Metered Guidelines

Statistical sampling for residential customers:

Residential customers without interval metering may participate in the Synchronized Reserve, Capacity, and Energy markets using a statistical sample extrapolated to the population to determine compliance and energy settlements. The sample data must be from the same time interval as the event being settled.

Qualifications:

A registration may participate using statistical sampling to determine compliance and energy settlements under the following conditions, and subject to PJM approval:

- The registration consists entirely of residential customers.
- Locations can be sampled to accurately reflect the population load data.
- Curtailment at each location uses Direct Load Control Technology.
- Synchronized Reserve: Locations otherwise qualify for participation in the Synchronized Reserve Market. Locations do not have meters that record load data at a period of 1 minute or shorter.
- Economic Energy: Locations otherwise qualify for participation in the Economic Energy Markets. Locations do not have meters that record load data at a period of 1 hour or shorter.
- Load Management: Locations otherwise qualify for Load Management. Locations do not have meters that record load data at a period of 1 hour or shorter.

Sample Design:

Samples must be designed to achieve a maximum error of 10% at 90% confidence. The locations in the sample must be randomly selected from all the locations in the population group (a population group is a group of registrations that can share a sample based on the criteria listed below). The sample must be stratified by control device size (minimum of 2 strata) and geographic location, unless otherwise approved by PJM.

For Load Management registrations that participate in the energy market, a sample is required for each combination of EDC, CSP, end-use device (such as air conditioner or water heater) or device grouping, curtailment algorithm and switch vintage if there is substantial variation among installed switch capability.

For economic registrations that participate in the Energy Markets, a sample is required for each combination of dispatch group or registration, end-use device or device grouping, curtailment algorithm, and switch vintage if switch capability is substantially different.

For economic registrations that participate in the Synchronized Reserve market, a sample is required for each combination of SR subzone, dispatch group or registration, end-use device or device grouping, curtailment algorithm, and switch vintage if switch capability is substantially different.

Sample Size Determination:

A variance study is used to determine the initial sample size. Interval data must be collected from at least 75 randomly selected and stratified customers during the season the end use device is in use in order to determine the variance of the load data for the sample. Synchronized Reserves: At least 2 weeks of continuous meter data collected at a period of 1 minute or smaller.

Load Management and Economic Energy: At least 4 weeks of continuous meter data collected at a period of 1 hour or smaller.

The number of locations in the sample is then calculated as follows, unless otherwise approved by PJM:

$n = \text{number of sampled customers in variance study}, \geq 75$

$X_{i,t} = \text{meter reading for customer } i \text{ during interval } t$

Calculate the mean and variance of the meter data across all customers for each interval:

$$\text{Mean}(X_t) = \overline{X_t} = \frac{1}{n}\sum_{i=1}^{n} X_{i,t}$$

$$\text{Var}(X_t) = \text{s}_{\text{X}_\text{t}}^2 = \frac{1}{n}\sum_{i=1}^{n}\left(X_{i,t} - \overline{X_t}\right)^2$$

Calculate the sample size necessary to get 10% error at 90% confidence for each interval:

$$M_t = \left(\frac{Z_{\alpha/2}}{e}\right)^2 \frac{\text{s}_t^2}{\overline{X_t}^2}$$

Where

$$Z_{\alpha/2} = 1.645 = \text{critical value at 90\% confidence } (\alpha = 0.1)$$

$e = 0.1 = \text{error}$

Take the average sample size across all intervals to determine *M*, the sample size:

$$M = \frac{1}{T}\sum_{t=1}^{T} M_t$$

Where T is the total number of intervals. T should be at least 20,160 for SR (2 weeks of 1 minute intervals) and 672 for economic energy and Load management (4 weeks of hourly intervals).

Alternate calculations may be used subject to PJM approval.

Sample Recalibration:

The sample must be recalibrated annually as follows:

1. The sample size must be recalculated using the same method listed above using data from all locations in the sample.
2. If the population was expanded in a non-random manner, the sample must be expanded appropriately, so that the sample is representative of the population.
3. The number of locations in each stratum in the sample must be adjusted so that the number of locations in each stratum is proportional to the population in that stratum within +/- 1 location.

Data Validation and Estimation:

Data must be validated and estimated in accordance with the NAESB Validating, Editing, and Estimating (VEE) Protocol. This protocol should be used for validation and estimation of 1-minute data for the SR market as well as hourly data for capacity and energy markets. Note: All rules for hourly data shall apply to 1 minute data where the only difference is the use of 1 minute interval instead of 1 hour interval.

If 5 minutes or more are missing or faulty from 1 minute meter data for a single event, or 2 hours or more are missing or faulty from hourly meter data for a single event, data from that meter may not be used for that event. If there is 1 way switch communication, the data for that meter must be reported as the PLC level for every reported interval on the event day. If there is 2 way switch communication and a sufficient number of locations in the sample without the missing meter data to meet the minimum sample size, then the an estimate for the missing meter data should not be reported for this event. If there is 2 way switch communication and an insufficient number of locations in the sample without the missing meter data to meet the minimum sample size, then the PLC value should be reported for every reported interval for the event day for each location with missing meter data such that there are enough locations to meet the sample requirements unless otherwise approved by PJM.

Example with one-way switch communication: The minimum required sample size is 300. There are 305 meters in the sample. 7 meters have missing or faulty data that cannot be corrected. The CSP must include data from the 298 correctly functioning meters, and report the data from the 7 faulty meters as the PLC value for each of the 7 EDC accounts for every reportable hour that day.

Example with two-way switch communication: The minimum required sample size is 300. There are 305 meters in the sample. 7 meters have missing or faulty data that cannot be corrected. The CSP must include data from the 298 correctly functioning meters, and report the data from 2 randomly selected faulty meters as the PLC value for those 2 EDC accounts for every reportable hour that day.

Switch Operability

Two-way switch communication: Two-way switch communication is when the CSP receives verification from the switch that it successfully cycled base on CSP instruction. When there is two way switch communication in place, the CSP will calculate the performance factor, *F*, as the total number of switches in the population that were sent the instruction to cycle for that event divided by number of switches in the population that successfully cycled for that event. The meter data will be multiplied by this value before submission to PJM to scale the sample average load data to the represent the population that performed the load reductions.

One-way switch communication: One-way switch communication is when the CSP cannot accurately determine if each switch in the population successfully cycled based on CSP instruction. In this case the operability value is implicit in the sample. The CSP must report all data from all meters in the sample, even if a switch in the sample is faulty. The CSP may not repair any faulty devices in the sample that could also be faulty in the population (for example an air conditioner cycling switch cannot be repaired/replaced but a 1-minute meter could be repaired/replaced) unless the CSP repairs/replaces those same devices that are faulty in the population. Switch failure in the sample must be reported to PJM within 2 business days.

Converting sample data to meter data

Note that the sample data must be from the same time interval being settled.

$X_{i,t}$ is the meter reading for customer i during interval t after VEE protocol is applied per this Manual.

B is the
$=$ set of EDC accounts in sample that are to be included in estimation (after subject to rules in this manual)

M_s = Sample size (number of EDC accounts in B)

M_c = *Population of* Cycled customers

F is the opearbility factor, calculated subject to this manual (1 for one way switch communication)

The meter data value to be submitted to PJM for interval t is Y_t:

$$Y_t = F\frac{M_c}{M_s}\sum_{i \in B} X_{i,t}$$

Measurement and Verification Plan

The CSP must submit a Measurement and Verification (M&V) plan to PJM before the registration is submitted. The M&V plan must be approved by PJM before the registration is submitted. CSP is to resubmit an updated M&V plan annually to continue participation in the PJM markets.

The M&V plan must include details on: how the variance study was conducted and sample size was determined; sample selection and stratification; meter qualification and quality assurance; data validation and error correction protocol; and how sample meter data will be converted to population meter data. A template of the M&V plan is to be published on pjm.com.

Churn and Customer Documentation

Note: Parts of this section apply to interval metered residential customers, as indicated below.

Applicable to all residential customer registrations (interval metered and non-interval metered):

- CSP to submit initial list of customers to PJM at time of registration, including all EDC account numbers PLCs and zip codes. Where legal or regulatory conditions prohibit provision of EDC account number as personally identifiable customer information the EDC may use unique identifying numbers for EDC account numbers, through 5/31/16 or as otherwise approved by PJM. EDC is responsible to maintain list of EDC account numbers and associated unique identifying numbers when used. EDC may need to check for duplicate as approved by PJM.

- Replacement allowed for customer who moves from their premises or customer terminates contract with CSP.
- CSP must maintain list of all replacement and furnish to PJM within 2 business days of request.
- CSP must maintain list of customers who were cycled during an event.
- All customer lists, meter data, and documentation must be furnished to PJM within 2 business days of request and be maintained by CSP for 2 years.

Applicable to interval-metered Load Management:

- CSP to submit list of PLC values for each EDC account at time of registration.
- Replacement customers must be selected to maintain PLC and load drop.
- CSP must maintain list of customers for each event and maintain for 2 years from event date.
- CSP may not add/remove customers (other than replacement). If number of customers falls below registered number, CSP must report to PJM within 2 business days and is subject to RPM Resource Deficiency Charges if applicable.

Applicable to non-interval metered Load Management:

- CSP to submit list of PLC values for each EDC account at time of registration.
- Replacement customers must be randomly selected to maintain integrity of strata, and if applicable PLC and load drop.
- CSP must maintain list of customers for each event and maintain for 2 years from event date.
- CSP may not add/remove customers (other than replacement). If the number of customers falls below registered number, CSP must report to PJM within 2 business days and is subject to RPM Resource Deficiency Charges if applicable.

Applicable to interval metered Economic Energy and Synchronized Reserve:

- There are no restrictions on replacement customers since actual meter data is submitted.
- CSP must maintain list of customers for each offer for 2 years from date of offer.
- CSP may add/remove customers at any time, but must maintain documentation and update the value on the location in eLRS. This value must be accurate every day an offer is submitted.

- List of offered customers must be finalized at time of offer. Number of offered customers cannot exceed number of customers on location.

Applicable to non-interval metered Economic Energy and Synchronized Reserve:

- Replacement customers must be randomly selected to maintain the integrity of the strata.
- CSP must maintain list of customers for each offer for 2 years from date of offer.
- CSP may add/remove customers at any time, if it can be done such that the sample remains representative of the population. CSP must maintain documentation and update the value on the location in eLRS. This value must be accurate every day an offer is submitted.
- If CSP offers partial list of customers to market, then such customers must be randomly assigned from pool of all registered customers. List of offered customers must be finalized at time of offer. Number of offered customers cannot exceed number of customers on location.

Revision History

Revision 28 (08/03/2015):

- Conforming revisions for FERC Order ER15-1849, accepted on 7/23/15 and effective 8/3/15, to improve measurement and verification procedures for CSPs with Residential Demand Response Customers. Direct Load Control is re-defined as Legacy Direct Load Control and is only effective through May 31, 2016. Statistical sampling may be used instead of customer-specific measurement and verification information for residential customers without interval metering, as outlined in Attachment D of this manual.

Revision 27 (03/26/2015):

- Section 3.2: Revised DR forecast methodology

Revision 26 (11/01/2014):

- Section 3: Revised to clarify the current process of applying adjustments to load forecasts.
- Attachment C: Added to provide guidelines for load forecast adjustments and examples.

Revision 25 (06/01/2014):

- Conforming revisions for FERC Order ER14-822, accepted on 05/09/2014, and effective on 06/01/2014 for various DR operational changes.
- Attachment A updated for new distinction between Emergency and Pre-Emergency DR.

Revision 24 (04/11/2014):

- Two of the eSuite Applications have been renamed. Moving forward EES will be known as ExSchedule and eMTR will be known as Power Meter.

Revision 23 (6/1/2013):

Section 3: Exhibits 2 and 3 revised to reflect updated economic and weather station mappings. The definition of winter load management is revised.

Attachment B; added specific requirements for load management switch operability studies.

Revision 22 (2/28/2013):

- Administrative Change: update all references of “eSchedules” to “InSchedules”

Revision 21 (10/01/2012):

Attachment A revised to add guidelines for load drop estimates for Price Responsive Demand participants.

Revision 20 (06/28/2012):

Attachment A updated based on PJM Interconnection, L.L.C., Docket No. ER11-3322 (Capacity measurement and verification). This tariff and RAA update specifically requires GLD to provide reductions below the PLC and aligns any recognized reductions used to determine capacity compliance with add back process.

Revision 19 (02/23/2012):

Attachment A changed to update Comparable Day definition, clarify data required if Generation data is used to substantiate load reduction and have PJM perform the compliance calculation.

Revision 18 (11/16/2011):

Section 3: Revisions reflect adoption of Itron, Inc recommendations regarding the economic driver used in the load forecast model. References to the now-defunct Interruptible Load for Reliability option of Load Management were removed.

Revision 17 (07/14/2011):

Attachment A: 24 hour data submission required and additional clarification for use of generation data to substantiate compliance (FERC Docket #: ER11-2898-000, 4/18/11). Also added revisions concerning how add backs are applied to DLC as approved by the MRC.

Revision 16 (04/01/2011):

Section 3: Integrated the description of the net energy forecast model into the general model description.

Revised Exhibits 2 and 3 to reflect updated economic and weather station mappings.

Attachment A: Revised load drop estimate guidelines based on Load Management Task Force proposal approved at November 2010 Markets and Reliability Committee and January 2011 Members Committee. Corresponding tariff language changes were filed with FERC under Docket ER11-2898-000.

Revision 15 (10/01/2009):

Attachment A: Revised load drop estimate guidelines to reflect the FERC-approved business rules. Section 3: added price responsive demand to the adjustments made to the load forecast.

Revision 14 (12/01/2008):

Section 3: Revised load forecast model specification to allow for a load adjustment dummy variable. Clarified the review and approval process for the Load Forecast Report.

Section 4: Revised the Weather Normalization approval process to clarify that Board approval is not required.

Revision 13 (06/01/2008):

A new Exhibit 1 was added, presenting definitions of variables used in the load forecast model. Other exhibits were re-numbered.

Exhibit 2 was revised to reflect a new weather station assignment for the DAY zone.

Section 4: Removed note from Weather Normalization Procedure description (the process is finalized).

Attachment A: Revised to reflect that the guidelines apply to both capacity- and energy-related load drop estimates.

Revision 12 (06/01/2007):

Removed Section 3 and moved content to Manual 18.

Removed Section 7 and moved content to Manual 18.

Revision 11 (06/01/07):

This extensive revision incorporates changes to Load Data Systems due to the implementation of the Reliability Pricing Model (RPM). Sections on Active Load Management and Qualified Interruptible Load have been replaced with a new Load Management section. The Zonal Scaling Factor section reflects a revised calculation. The Load Forecast Model section has been updated for enhancements made to the model specification as well as revised coincident peak forecast method. The Weather Normalization section was revised to reflect that seasonal peaks are now normalized using the load forecast model.

Revision 10 (06/01/06):

- Exhibit 1—Updated to include the new Manual 30: Alternative Collateral Program.
- Section 3—Revised to reflect changes in the handling of outlier observations in weather normalization of seasonal peaks.
- Section 4—Revised to incorporate the addition of the Full Emergency option of Load Response.
- Updated the penalties/rewards section under Compliance.

Revision 09 (01/01/06):

This revision includes a complete revision to Section 6 to detail the PJM-produced load forecast which will be used for capacity and system planning purposes. The previous Section 3 (PJM Load Forecast Report) has been removed since Member input is no longer required for its production.

Revision 08 (06/01/05):

Updated Exhibit 1 to include new PJM Manuals.

This revision includes changes to Section 3 to reflect reporting requirements for sub-Zones. Section 4 was completely revised to reflect a new weather normalization method and revised basis for calculating 5CPs. Section 8 has been modified to reflect revised release dates for Zonal Scaling Factors.

Revision 07 (07/01/04):

This revision includes changes to Section 2, to reflect that 500kV generation will be treated differently in the PJM Western and Southern regions than the Mid-Atlantic Region. Section 4 was revised to reflect that peak load allocation will be impacted for market integration. Section 5 has been modified to reflect that the Active Load Management program has been fully incorporated into the eCapacity application.

Revision 06 (10/01/03):

This revision incorporates a new presentation format. Substantive changes were made to Section 4, to reflect changes in peak normalization procedures. Section 5 and Attachment B were revised to reflect the change in load research requirements for cycling programs to a five year cycle. The previous Section 6 (Forecast Peak Period Load) has been deleted. The section on Qualified Interruptible Load now reflects that it is the same as Active Load Management. New sections have been added for the PJM Entity Forecast and Zonal Scaling Factors. Attachment A includes an additional load drop estimate technique, Customer Baseline. Throughout the document, changes were made to reflect the new committee structure, and the Board of Managers enhanced authority.

Changed all references from "*PJM Interconnection, L.L.C.*" to "*PJM.*"

Changed all references from "the PJM OI" to "PJM."

Renamed Exhibits to consecutive numbering.

Reformatted to new PJM formatting standard.

Renumbered pages to consecutive numbering.

Revision 05 (01/01/03):

This revision contains changes to Section 2, which was revised to reflect that hourly load data are reported through the new Power Meter application. Section 5 was revised to clarify wording on existing Active Load Management rules and procedures.

Revision 04 (06/01/02):

This revision contains changes to Section 3, which was revised to reflect a new reporting format for the PJM Load Forecast Report. Section 7 was revised to incorporate firm level customers into the Qualified Interruptible Load program.

Revision 03 (01/01/02):

This revision incorporates changes resulting from the addition of PJM West into the Interconnection. Section 4 was revised to add a description of the peak normalization process for PJM West. Sections 6 (Qualified Interruptible Load) and 7 (Forecast Period Peak Load) were added.

Revision 02 (10/01/00):

This revision contains changes to Section 4 to include a clarification of the weather normalization overview, and revises the summer season weather normalization to reflect the newly adopted PJM summer weather parameter. Also, the removal of Attachment A: Definitions and Abbreviations. Attachment A is being developed into a 'new' PJM Manual for *Definitions and Abbreviations (M-35)*. Attachments B, C, and D have been renamed A, B, and C respectively. Also, changes to the 'new' Attachment A: ALM Load Drop Estimate Guidelines (previously listed as Attachment B) have been in effect since 6/01/00; however, they are now being addressed in this revision.

Revision 01 (06/01/00):

This revision contains changes to Sections 3, 4, and 5, to reflect the influence of retail choice, including the creation of a peak allocation, revamped Active Load Management rules and procedures, and revamped PJM Load Forecast Report. Also, it details a revised weather normalization procedure.

Revision 00 (07/15/97):

This revision is the complete draft of the PJM Manual for Load Data Systems.

OCC NOPEC Ex 11-A

ERRATA TO KAHAL SECOND SUPPLEMENTAL DIRECT TESTIMONY

Page 14, lines 5 and 16, change $3.2 to $2.9

Page 18, line 13, change $2,969 to $2,713

Page 18, line 15, change $3,912 to $3,614

Page 19, line 12, change $4,102 to $3,803 and change $4,192 to $3,893

Page 27, line 4, change $2,969 to $2,713

Page 27, line 5, change $3,260 to $3,350 to $2,902 to $2,992

Page 36, line 8, change $3.2 to $2.9

Page 36, line 15, change $3.2 to $2.9 and change $4 to $3.8

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EXHIBIT
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