EXHIBIT NO. 45



2024 Load Forecast Supplement

PJM Resource Adequacy Planning Department

January 2024

For Public Use

This page is intentionally left blank.

Contents

.....1

Contents ii

Introduction and Overview.....1

Summary of Changes from 2023 Methodology.....1

Sector Models 1

Residential.....1

Commercial 5

Industrial.....7

Usage Indexes.....8

Weather Variables.....9

Cooling and Heating Degree Variables.....10

Additional Weather Variables 11

Forecast Model.....12

Model Specification.....12

Binary and Trend Variables..... 13

Simulation 14

Coincident Peaks.....15

Assumption Development.....15

Weather.....15

Vendor Data.....15

Plug-in Electric Vehicles 16

Behind-the-Meter Battery Storage Operation.....18

Exogenous Factors 18

AEP – Data Centers and Computer Chip Plant 19

APS – Data Centers..... 20

PS – Data Centers and Port Electrification 21

Dominion – Data Centers..... 23

EKPC – Peak Shaving Adjustment 25

NRBTMG to DR 26

State Policy 26

Additional Model Detail 27

Calendar Variables 27

Zonal End-Use Variable Calibration 30

Economics Zonal Geographic Assignment.....34

Addition of HD3 Variable.....35

Introduction and Overview

This document serves as a supplement to the 2024 PJM Load Forecast report. It is intended as a reference, to provide details of the processes used to develop the load forecast and the data and assumptions used. It describes the load forecast model that produces the forecast as well as non-model adjustments to it.

This document acts as a resource to help describe the load forecast process. For details such as parameter estimates and model outputs, additional resources are available on the PJM website: https://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process.aspx.

This is the second year in which PJM has employed the use of an hourly forecast model, as a result of a multi-month engagement in 2022 with Itron. Their final report can be found here (https://www.pjm.com/-/media/planning/res-adeq/load-forecast/pjm-model-review-final-report-from-itron.ashx) and should be viewed in conjunction with PJM documentation.

Summary of Changes from 2023 Methodology

PJM contracted with S&P Global to provide an electric vehicle forecast for use in the 2024 Load Forecast. S&P Global provided PJM with zonal vehicle counts and charging impacts for light, medium, and heavy duty electric vehicles.

PJM added a third cold variable to the forecast model that acts like a spline when weather gets very cold. The HD3 variable adds another breakpoint after our HD2 variable. These HD variables are meant to capture different relationships of load to weather under different conditions. The additional cold weather variable, HD3, was added in response to testing after Winter Storm Elliott.

Sector Models

Sector models are a key part of the load forecast process, providing insights into why load trends are happening. The job of a forecaster is to use models to understand what has happened such that they can make an informed judgment about the future. Looking at total peak and energy trends over time only tells us part of the story: what is happening. Sector models can give us greater insight into why things are happening.

Sector models are where we incorporate the independent assumptions on economic trends and end-use adoption and efficiency. The load forecast process considers three sectors: Residential, Commercial, and Industrial. Each sector has its own set of models and inputs.

Residential

The Residential Sector model is actually two models, a customer model and an average use model. The product of these two concepts—customers and average use—provides total residential use. Total Residential use is considered according to the three use classes of Heating, Cooling, and Other.

Customers are modeled for each zone as a function of households. Monthly customer data is obtained from the EIA 861 dataset. Households are an economic concept, with quarterly history and forecast provided by Moody's Analytics. The relationship of customers to economics is defined by the below equation.

Equation 1. **Residential Customers**

$$customers = B_1 * households + B_2 * y2021$$

Where

y2021 = 1 when year is greater than or equal to 2021 and 0 otherwise

Average use per customer is modeled as a function of Heating, Cooling, and Other. Average use data is obtained from the EIA 861 dataset. Heating, Cooling, and Other are functions of end-use concepts provided by Itron (based on data from the EIA's Annual Energy Outlook) and economic concepts that are provided by Moody's Analytics (household size and real household income). The relationship of average use to Heating (xheat), Cooling (xcool), and Other (xother) is defined by the below equation.

Equation 2. **Residential Average Use**

$$use_t = B_0 * xheat_t + B_1 * xheat_{t-1} + B_2 * xcool_t + B_3 * xcool_{t-1} + B_4 * xother_t$$

The table below provides a list of residential end-uses and indicates how they are allocated to Heating, Cooling, and Other. For each end-use, data provided by Itron includes saturation (% of customers with device), efficiency (relative efficiency of device), and intensity (use per device accounting for saturation and efficiency).

Table 1. **List of Residential End-Uses and Assignment**

Bucket	Use Type	Definition
Heating	EFurn	Electric furnace and resistant room space heaters
Heating	HPHeat	Heat pump space heating
Heating	GHPHeat	Ground-source heat pump space heating
Heating	SecHt	Secondary heating
Cooling	CAC	Central air conditioning
Cooling	HPCool	Heat pump space cooling
Cooling	GHPCool	Ground-source heat pump space cooling
Cooling	RAC	Room air conditioners
Other	EWHeat	Electric water heating

Other	ECook	Electric cooking
Other	Ref1	Refrigerator
Other	Ref2	Second refrigerator
Other	Frz	Freezer
Other	Dish	Dishwasher
Other	CWash	Electric clothes washer
Other	EDry	Electric clothes dryer
Other	TV	TV sets
Heating	FurnFan	Furnace fans
Other	Light	Lighting
Other	Misc	Miscellaneous electric appliances[1]

Heating (xheat) is a function of heating end-uses as identified in the above table with adjustments for weather, real income per household, population per household, and building shell efficiency.

Equation 3. **Residential Heating Variable (xheat)**

$$xheat_t = sae_heat_t * hdd_in_t$$

Where

$$sae_heat_t = (EFurn_t + HPHeat_t + GHPHeat_t + SecHt_t + FurnFan_t) * (Population_per_houeshold_t)^x * (Income_per_household_t)^y * Structural_Heating_t$$

Where x and y are elasticities provided by Itron and Structural_Heating is a measure of building size adjusted for relative building shell efficiency.

and

[1] Residential end-use data has always included a category referred to as Miscellaneous, which represented a catch-all of the non-named appliances listed. In 1998, Miscellaneous represented about a fifth of non-weather sensitive uses and now represents about half; a trend spurred as much by growth in Miscellaneous as declines in non-Miscellaneous end-uses.

$$hdd_in_t = \frac{hdd_t}{hdd_{2016}}$$

Cooling (xcool) is a function of cooling end-uses as identified in the above table with adjustments for weather, income per household, population per household, and building shell efficiency.

Equation 4. **Residential Cooling Variable (xcool)**

$$xcool_t = sae_cool_t * cdd_in_t$$

Where

$$sae_{cool_t} = (CAC_t + HPCool_t + GHPCool_t + RAC_t) * (Population_per_houeshold_t)^x * (Income_per_household_t)^y * Structural_Cooling_t$$

Where x and y are elasticities provided by Itron and Structural_Cooling is a measure of building size adjusted for relative building shell efficiency.

and

$$cdd_in_t = \frac{cdd_t}{cdd_{2016}}$$

Other (xother) is a function of other end-uses as identified in the above table with adjustments for income per household, and population per household.

Equation 5. **Residential Other Variable (xother)**

$$xother_t = sae_other_t * Days_Idx_t$$

Where

$$sae_{other_t} = (EWHeat_t + ECook_t + Ref1_t + Ref2_t + Frz_t + Dish_t + CWash_t + EDry_t + TV_t + Light_t + Misc_t) * (Population_per_houeshold_t)^x * (Income_per_household_t)^y$$

Where x and y are elasticities provided by Itron

and

$$Days_Idx_t = \frac{Days\ in\ Month}{30.42}$$

The results of Equation 2 (Residential Average Use) are fitted values, which includes historical weather. For comparability in heating and cooling trends over time, this then needs to be transformed to be on a consistent weather basis.

Equation 6. **Formulation of HeatUse, CoolUse, and OtherUse**

Heating and Cooling are adjusted to be consistent with 2016 weather for all years.

$$HeatUse_t = B_0 * norm_xheat_t + B_1 * norm_xheat_{t-1}$$

$$CoolUse_t = B_2 * norm_xcool_t + B_3 * norm_xcool_{t-1}$$

$$OtherUse_t = B_4 * xother_t$$

where B0, B1, B2, B3, and B4 are from Equation 2

and

norm_xheat and *norm_xcool* are the same as *xheat* and *xcool* but using 2016 weather

Total residential use then is the product of customers and each of these defined average use terms.

Equation 7. **Total Residential Use**

$$ResHeat_t = Customers_{quarter,year} * HeatUse_{quarter,year}$$

$$ResCool_t = Customers_{quarter,year} * CoolUse_{quarter,year}$$

$$ResOther_t = Customers_{quarter,year} * OtherUse_{quarter,year}$$

Commercial

The starting point for analysis is Commercial energy provided through the EIA 861 dataset. The Commercial models utilize two sets of data: economic and end-use. Economic concepts used are service sector employment, working-age population, and real services output, and are provided by Moody's Analytics. End-use concepts are provided by Itron (based on data from the EIA's Annual Energy Outlook), and are summarized in the following table.

Table 2. **List of Commercial End-Uses and Assignment**

Bucket	Use Type	Definition
Heating	Heating	Heating
Cooling	Cooling	Cooling
Other	Ventilation	Ventilation
Other	WtrHeat	Water Heating
Other	Cooking	Cooking

Other	Refrig	Refrigeration
Other	Lighting	Lighting
Other	Office	Office Equipment (PCs)
Other	Misc	Miscellaneous

Equation 8. **Commercial Use**

$$use_t = B_0 * xheat_t + B_1 * xheat_{t-1} + B_2 * xcool_t + B_3 * xcool_{t-1} + B_4 * xother_t$$

Where

$$xheat_t = Heat_t * \ ComEconVar_t * hdd_in_t$$

$$xcool_t = Cool_t \ * \ ComEconVar_t * cdd_in_t$$

$$xother_t = Other_t \ * \ ComEconVar_t$$

Heat, *Cool*, and *Other* are end-use intensities from categories in the above table. *ComEconVar* is a 30/30/40 weighed combination of services employments, real services output, and working-age population, respectively.

For comparability in heating and cooling trends over time, this then needs to be transformed to be on a consistent weather basis.

Equation 9. **Formulation of HeatUse, CoolUse, and OtherUse**

Heating and Cooling are adjusted to be consistent with 2016 weather for all years.

$$Com_Heat_t = B_0 * norm_xheat_t + B_1 * norm_xheat_{t-1}$$

$$Com_Cool_t = B_2 * norm_xcool_t + B_3 * norm_xcool_{t-1}$$

$$Com_Other_t = B_4 * xother_t$$

where B0, B1, B2, B3, and B4 are from Equation 8

and

norm_xheat and *norm_xcool* are the same as *xheat* and *xcool* but using 2016 weather

Industrial

The starting point for analysis is Industrial energy provided through the EIA 861 dataset. Industrial modeling utilizes two sets of data: economic and intensity. The economic concept used is real industrial output, using data from Moody's Analytics. Intensity data is pulled from national data from EIA on electricity per real output.

Real industrial output is an aggregate of output in goods-producing industries (see list). Moody's Analytics currently only forecasts employment for these series at the metro area level, not output. However, output is available at the state level and thus output at the metro level is imputed by using state productivity (output divided by employment).

Equation 10. **Metro Area Real Industrial Output**

$$\boldsymbol{Output}_{\boldsymbol{sector,metro,year}} = \boldsymbol{Employment}_{\boldsymbol{sector,metro,year}} * \boldsymbol{Output}_{\boldsymbol{sector,state,year}} / \boldsymbol{Employment}_{\boldsymbol{sector,state,year}}$$

$$\boldsymbol{Output}_{\boldsymbol{metro,year}} = \sum_{\boldsymbol{sector}} \boldsymbol{Output}_{\boldsymbol{sector,metro,year}}$$

where metro areas are assigned to states based on location

And Sectors are defined as follows:

Natural Resources and Mining

Construction

Manufacturing – Machinery

Manufacturing - Transportation Equipment

Manufacturing - Chemicals; Energy; Plastics and Rubber

Manufacturing - Electronic and Electrical

Manufacturing - Furniture and Miscellaneous

Manufacturing - Metals and Mining

Manufacturing - Textile; Fiber and Printing

Industrial intensity is defined as industrial energy use per real output. The concept is based on national data, but is customized to zones through the availability of sector detail. Historical and forecast energy use by sector is compiled from the EIA Annual Energy Outlook (AEO) and the EIA Manufacturing Energy Consumption Survey (MECS). Economic data by sector is provided by Moody's Analytics as was described in the prior paragraph. Zonal industrial intensity series are then a weighted average of national sector indexes.

Equation 11. **Zonal Industrial Intensity**

$$Intensity_{year} = \sum_{sector} (Output_{sector,year} / Total\ Output_{year}) * Intensity_{sector,year}$$

Discussed above are the types of inputs considered, but as discussed in Itron's model review[2] it is challenging to fit all zones with a structural end-use model. Candidate models that consider the above described variables are constructed, and are evaluated on a zone-by-zone basis for goodness of fit and reasonableness. Reasonableness checks include items such as ensuring coefficients have the right sign and how the model performs on out-of-sample observations. Zonal industrial model selections are provided in supplemental posted materials. Each zone results in an Industrial Base component (*Ind_Other*) and in some cases an Industrial Cooling component (*Ind_Cooling*).

Equation 12. **Industrial Cooling**

$$Ind_Cooling_t = B * CDD_{2016}$$

Where *B* is the coefficient on the cooling term in the industrial model. Cooling is included in zones for which it has a positive coefficient, and excluded for which it does not.

Usage Indexes

Heat, Cool, and Other Usage Indexes need to be constructed using the results from the Residential, Commercial, and Industrial Sector Models. First, monthly results are rolled up into single measures.

Equation 13. **Monthly Results**

$$Heat_t = Res_Heating_t + Com_Heating_t$$

$$Cool_t = Res_Cooling_t + Com_Cooling_t + Ind_Cooling_t$$

$$Other_t = Res_Other_t + Com_Other_t + Ind_Other_t$$

At this point, *Other* is essentially complete and is simply converted from a monthly frequency to a daily frequency with each day's value within a month equal to the respective monthly value. *Heat* and *Cool* though at this point are still reflective of 2016 weather patterns in HDD and CDD. A 365 day moving average is taken of each to calculate *HeatIdx* and *CoolIdx*, such that these can later be interacted with hourly heating and cooling weather variables to capture weather sensitive load over time.

[2] See pages 15 and 16 for Itron's discussion of Industrial modeling: https://www.pjm.com/-/media/planning/res-adeq/load-forecast/pjm-model-review-final-report-from-itron.ashx

Weather Variables

Weather variables are defined at the zone level. Zonal weather is a weighted average of weather stations[3].

Table 3. **Weather Station Assignment**

Zone	Weather Station	Weight	Zone	Weather Station	Weight
AE	ACY	100.0%	JCPL	ACY	25.0%
AEP	CAK	15.1%	JCPL	EWR	75.0%
AEP	CMH	23.4%	METED	ABE	50.0%
AEP	CRW	22.6%	METED	PHL	50.0%
AEP	FWA	22.7%	PECO	PHL	100.0%
AEP	ROA	16.2%	PENLC	ERI	50.0%
APS	IAD	30.0%	PENLC	IPT	50.0%
APS	PIT	70.0%	PEPCO	DCA	100.0%
ATSI	CAK	46.5%	PL	ABE	25.0%
ATSI	CLE	30.0%	PL	AVP	25.0%
ATSI	PIT	8.5%	PL	IPT	25.0%
ATSI	TOL	15.0%	PL	MDT	25.0%
BGE	BWI	100.0%	PS	EWR	100.0%
COMED	ORD	100.0%	RECO	EWR	100.0%
DAYTON	DAY	100.0%	UGI	AVP	100.0%
DPL	ILG	70.0%	VEPCO	IAD	33.3%
DPL	WAL	30.0%	VEPCO	ORF	33.3%
DQE	PIT	100.0%	VEPCO	RIC	33.3%
DUKE	CVG	100.0%			
EKPC	CVG	25.0%			
EKPC	LEX	49.0%			
EKPC	SDF	26.0%			

[3] Weather station weights are provided by Electric Distribution Companies (EDCs).

Cooling and Heating Degree Variables

Temperature-Humidity Index (THI) values are translated to CD1, CD2, and CD3 in order to allow the forecast the flexibility to capture different relationships of load to weather under different conditions (a spline). The goal in defining cut points for CD2 and CD3 is to try have it hot enough to capture any potential inflection points but not so hot such that there is limited ability to make a good statistical inference.

Equation 14. **Temperature-Humidity Index and Cooling Degrees Formulas**

$$\boldsymbol{THI_t = temperature_t + 0.55 * (humidity_t/100 - .4) * max(temp_t - 58, 0)}$$

Base-points are set for each hour to calculate CD1, CD2, and CD3

Hour Ending	Base Point
1	65
2	65
3	65
4	65
5	65
6	65
7	65
8	65
9	65
10	65
11	65
12	70
13	70
14	70
15	70
16	70
17	70
18	70
19	70
20	70
21	65
22	65
23	65
24	65

$$\boldsymbol{CD1_t = \max(THI_t - \text{Base_Point}_{HE}, 0)}$$

$$\boldsymbol{CD2_t = \max(THI_t - \text{Base_Point}_{HE} + 10, 0)}$$

$$\boldsymbol{CD3_t = \max(THI_t - \text{Base_Point}_{HE} + 15, 0)}$$

Heating degree variables are then also used.

Equation 15. **Heating Degrees**

Base-points are set for each hour to calculate HD1, HD2, and HD3

Hour Ending	Base Point
1	55
2	55
3	55
4	55
5	55
6	55
7	55
8	55
9	55
10	55
11	55
12	60
13	60
14	60
15	60
16	60
17	60
18	60
19	60
20	60
21	55
22	55
23	55
24	55

$$HD1_t = \max(\text{Base_Point}_{HE} - Temp_t, 0)$$

$$HD2_t = \max(\text{Base_Point}_{HE} - 10 - Temp_t, 0)$$

$$HD3_t = \max(\text{Base_Point}_{HE} - 15 - Temp_t, 0)$$

These Cooling Degree and Heating Degree variables are used both contemporaneously as well as lagged transformations (Lag6CD, Lag24CD, Lag6HD, Lag24HD), interacted with weekend day-type (WkEndCD, WkEndHD), and interacted with seasons (SpringCD, FallCD, SpringHD, FallHD).

Additional Weather Variables

The load forecast model also includes variables to capture both wind speed and cloud cover.

Equation 16. **Wind and Cloud Variables**

$$WindHD_t = WSP_t * \min(HD1_t/60, 1)$$

$$WindCD_t = WSP_t * \min(CD1_t/60, 1)$$

Where *WSP* is a 3-period centered moving average of wind speed

$$CloudHD_t = Cloud_t * \min(HD1_t/60, 1)$$

$$CloudCD_t = Cloud_t * \min(CD1_t/60, 1)$$

Where *Cloud* is a 3-period centered moving average of wind speed

Forecast Model

Model Specification

The load forecast is constructed using 24 hourly models for each zone. In each model, load is the dependent variable. In the history, we start with metered load and then re-constitute with load management addbacks, load drops associated with peak shaving programs, and distributed solar generation estimates.

Each regression model has the same set-up, with load modeled against input variables: Weather Variables, Calendar effects, and Economic and End-Use considerations. Variable names align with documentations in the posted statistical appendix and are grouped below based on whether they are related to non-weather (XOther), heating (XHeat), or Cooling (XCool).

Equation 17. **Forecast Model Specification**

$$load = \sum_{variables} B_{variable} * variable$$

Where

Calendar-type variables (Interacts with XOther)

Intercept_XOther	JanWalk	Wednesday	XMasDay
Jan	FebWalk	Thursday	NYEve
Feb	MarWalk	Friday	NYDay
Mar	AprWalk	Saturday	WkAfterNewYear
MarDST	MayWalk	MLK	WkDayBeforeHol
Apr	JunWalk	PresDay	WkDayAfterHol
May	JulWalk	GoodFri	Phase1
Jun	AugWalk	MemDay	Phase2
Jul	SepWalk	July4th	Phase3
Aug	OctWalk	LaborDay	
Sep	NovWalk	Thanks	binary1
Oct	DecWalk	FriAThanks	binary2
Nov	Monday	WkBeforeXMas	trend1
NovDST	Tuesday	XMasEve	trend2

Heating-type Variables (Interacts with XHeat)

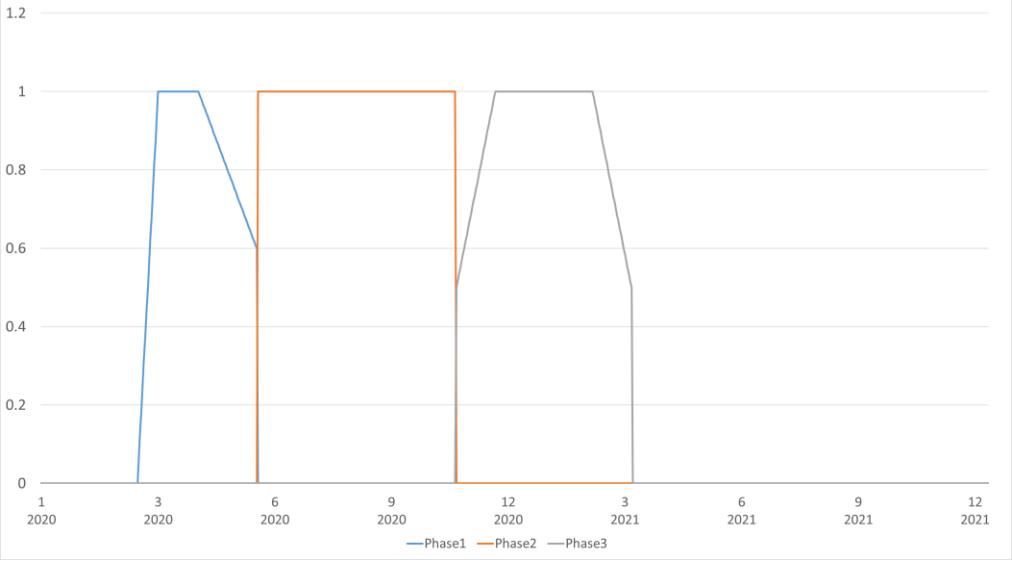
HD1	SpringHD
HD2	FallHD
HD3	WindHD
Lag6HD	CloudHD
Lag24HD	MA10_HDD
Lag24CD_HD	MA28_HDD
WkEndHD	

Cooling-type Variables (Interacts with XCool)

TD1	SpringCD
TD2	FallCD
TD3	WindCD
Lag6CD	CloudCD
Lag24CD	MA10_CDD
Lag24HD_CD	MA28_CDD
WkEndCD	

Binary and Trend Variables

COVID-19 had a large impact on electricity demand. Some of this impact is captured in aspects of the model construction via the economic inputs in the sector models. Nevertheless, it is often advisable in periods such as these to provide some controls for the abnormal event. The 2024 Load Forecast emplys an approach where a series of binaries are used *Phase1* through *Phase3* with the *Phase3* variable ending April 2021. This will continue to be re-visited each year.



In addition to COVID treatments, *binary1/binary2* and *trend1/trend2* variables are defined for each zone. These are intended to help tune the model and capture abnormal events in the residuals after specifying the model. None of

these trends are extended into the forecast period, so their effect is on the model parameterization and not on assumptions of future trends. Contained in the supplemental materials are hourly residual plots of before and after the inclusion of these additional model variables.

Simulation

Once the load model is estimated, forecasts for each PJM transmission zone are produced by solving the hourly zonal equations, moving through the year day by day and hour by hour applying historical weather patterns (including conditions for distributed solar generation), as well as forecast adjustments (data centers and peak shaving), behind-the-meter battery storage, and electric vehicles .

To model the most likely weather conditions (often referred to as normal or peak-eliciting weather), a weather rotation technique is used to simulate a distribution of hourly load scenarios generated by historical weather observations, representing actual weather patterns that occurred across the PJM control region.

To enhance the simulation process, each yearly weather pattern is shifted by each day of the week moving forward six days and backwards six days, providing 13 different weather scenarios for each historical year. For early January and late December dates, data from the same calendar year is applied. The table below illustrates the shift of weather data across the scenarios.

	Weather Scenarios												
		Rotate Forward						Rotate Backward					
Date	A1995	B1995	C1995	D1995	E1995	F1995	G1995	H1995	I1995	J1995	K1995	L1995	M1995
1-Jan	1/1/1995	1/2/1995	1/3/1995	1/4/1995	1/5/1995	1/6/1995	1/7/1995	12/31/1995	12/30/1995	12/29/1995	12/28/1995	12/27/1995	12/26/1995
2-Jan	1/2/1995	1/3/1995	1/4/1995	1/5/1995	1/6/1995	1/7/1995	1/8/1995	1/1/1995	12/31/1995	12/30/1995	12/29/1995	12/28/1995	12/27/1995
3-Jan	1/3/1995	1/4/1995	1/5/1995	1/6/1995	1/7/1995	1/8/1995	1/9/1995	1/2/1995	1/1/1995	12/31/1995	12/30/1995	12/29/1995	12/28/1995
4-Jan	1/4/1995	1/5/1995	1/6/1995	1/7/1995	1/8/1995	1/9/1995	1/10/1995	1/3/1995	1/2/1995	1/1/1995	12/31/1995	12/30/1995	12/29/1995
5-Jan	1/5/1995	1/6/1995	1/7/1995	1/8/1995	1/9/1995	1/10/1995	1/11/1995	1/4/1995	1/3/1995	1/2/1995	1/1/1995	12/31/1995	12/30/1995
6-Jan	1/6/1995	1/7/1995	1/8/1995	1/9/1995	1/10/1995	1/11/1995	1/12/1995	1/5/1995	1/4/1995	1/3/1995	1/2/1995	1/1/1995	12/31/1995
7-Jan	1/7/1995	1/8/1995	1/9/1995	1/10/1995	1/11/1995	1/12/1995	1/13/1995	1/6/1995	1/5/1995	1/4/1995	1/3/1995	1/2/1995	1/1/1995
-	-	-	-	-	-	-	-	-	-	-	-	-	-
25-Dec	12/25/1995	12/26/1995	12/27/1995	12/28/1995	12/29/1995	12/30/1995	12/31/1995	12/24/1995	12/23/1995	12/22/1995	12/21/1995	12/20/1995	12/19/1995
26-Dec	12/26/1995	12/27/1995	12/28/1995	12/29/1995	12/30/1995	12/31/1995	1/1/1995	12/25/1995	12/24/1995	12/23/1995	12/22/1995	12/21/1995	12/20/1995
27-Dec	12/27/1995	12/28/1995	12/29/1995	12/30/1995	12/31/1995	1/1/1995	1/2/1995	12/26/1995	12/25/1995	12/24/1995	12/23/1995	12/22/1995	12/21/1995
28-Dec	12/28/1995	12/29/1995	12/30/1995	12/31/1995	1/1/1995	1/2/1995	1/3/1995	12/27/1995	12/26/1995	12/25/1995	12/24/1995	12/23/1995	12/22/1995
29-Dec	12/29/1995	12/30/1995	12/31/1995	1/1/1995	1/2/1995	1/3/1995	1/4/1995	12/28/1995	12/27/1995	12/26/1995	12/25/1995	12/24/1995	12/23/1995
30-Dec	12/30/1995	12/31/1995	1/1/1995	1/2/1995	1/3/1995	1/4/1995	1/5/1995	12/29/1995	12/28/1995	12/27/1995	12/26/1995	12/25/1995	12/24/1995
31-Dec	12/31/1995	1/1/1995	1/2/1995	1/3/1995	1/4/1995	1/5/1995	1/6/1995	12/30/1995	12/29/1995	12/28/1995	12/27/1995	12/26/1995	12/25/1995

This approach has two key advantages. One, by rotating the data on the calendar, peak-producing weather will be applied to peak producing days. Two, by producing scenarios over a wide range of weather conditions, the weather rotation method is able to identify both the probable and possible levels of future peak load.

The process is repeated for the remaining years of historical weather data. The 2024 Load Forecast uses 29 years of weather history that results in 377 (29 weather years x 13 days) separate forecast simulations for each year in the forecast horizon. These simulations produce a frequency distribution of NCP demands by zone.

For each weather scenario, monthly NCPs are determined by obtaining the maximum NCP for the month. Seasonal NCPs are determined as the maximum over the summer/winter/spring/fall months. For each season, the ratio of each month's peak to the highest monthly peak is taken, and then each month's ratio is multiplied by the seasonal peak. In

this way, one of the month's peaks is the seasonal peak while still preserving the relationship between monthly peaks.

For purposes of system planning, only a couple of the values in the forecast distribution are used. After ranking the scenario forecasts from lowest to highest MW value, the median value is selected as the base (or 50/50) forecast. This is the value used for most system planning studies. The 90th percentile (or 90/10) result is used for studies where the system is assumed to be at system emergency conditions.

Coincident Peaks

Hourly results from the method described above are rolled up to the the entire PJM RTO and Locational Deliverabity Areas (LDA). Weather rotation provides an additional benefit for identifying coincident peaks - the natural diversity of weather patterns that impact the PJM footprint is simulated. This is a more plausible approach to peak forecasting than traditional methods which tend to have all weather stations having peak producing weather on the same day. Using the latter approach would overstate the PJM or LDA peak forecast by minimizing diversity.

Monthly RTO/LDA peaks are determined by obtaining the maximum for each scenario for each month (377 possible peaks). Seasonal RTO/LDA peaks are determined over the summer/winter/spring/fall months by obtaining the maximum for each scenario for each season (377 possible peaks). For each season, the ratio of each month's peak to the highest monthly peak is taken, and then each month's ratio is multiplied by the seasonal peak. 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 10/90 and 90/10 weather bands.

At this point, the values of the overall RTO peaks are set, but not the contribution of each zone. To determine the final zonal RTO/LDA-coincident peak forecasts, each zone's average contribution across the peak distribution is calculated and applied to the RTO forecast.

Assumption Development

Weather

The 2024 Load Forecast uses historical weather data from 1994 to 2022 as the basis for constructing forecasts. No explicit assumption is being made about Climate Change, and thus the assumption is that future weather will resemble past weather.

Vendor Data

The 2024 Load Forecast relies on vendor and government sources.

For economic and demographic forecasts, PJM consults with Moody's Analytics and used their September 2023 forecast vintage. Zonal charts for concepts used have been posted with the supplemental materials.

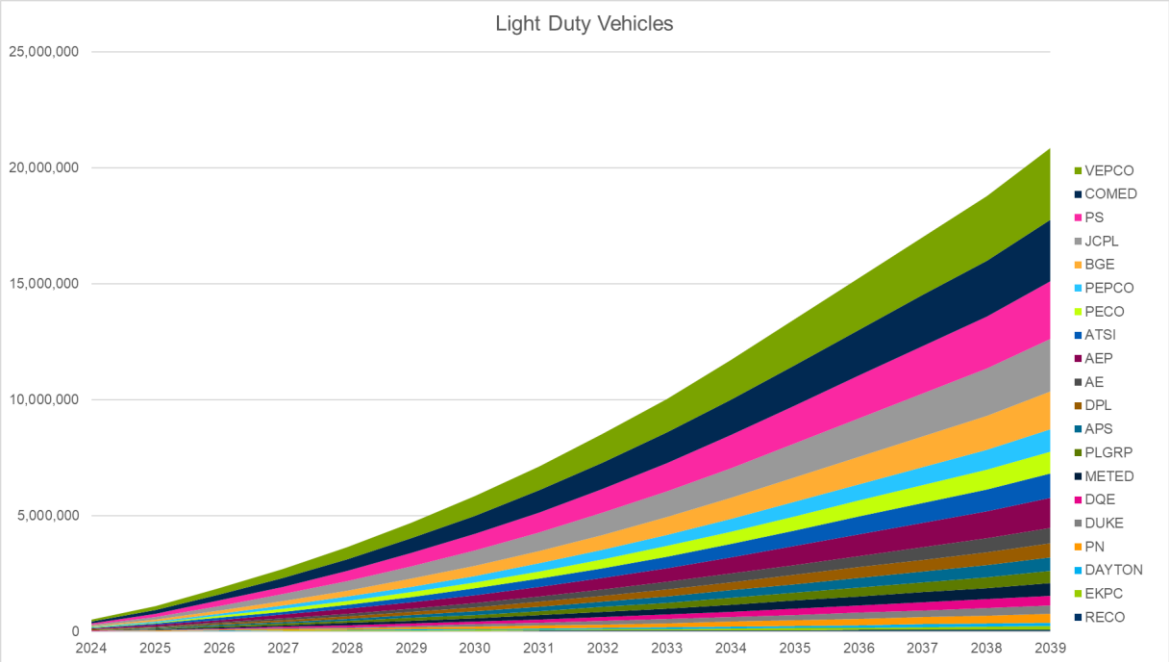
For end-use saturation/efficiency/intensity projections, PJM is a member of the Itron Energy Forecasting Group (EFG) that provides Census level history/projections for Residential/Commercial sectors. Their work derives from the Energy Information Administration's 2023 Annual Energy Outlook.

For distributed energy resources (BtM solar and storage), S&P Global provides a BtM solar and storage additions forecast. This is combined with historical Generation Attribute Tracking System (GATS) data in order to provide cumulative nameplate capacity by zone. UL provides zonal solar production estimates, which are used in both determining historical performance and expectations of future performance.

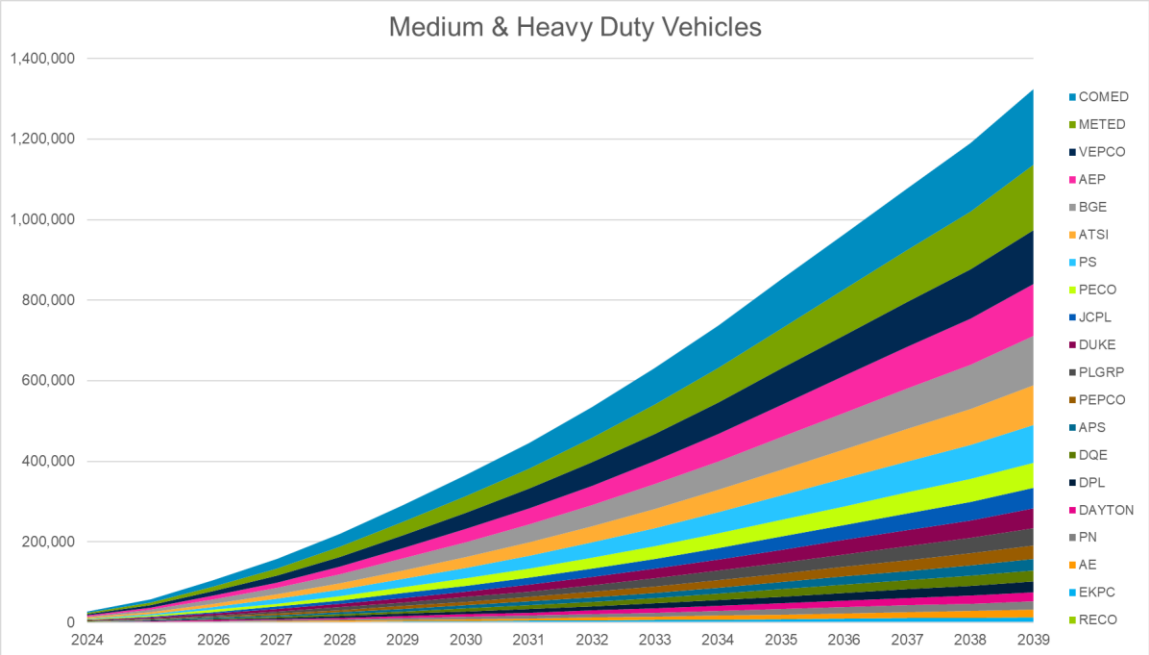
Plug-in Electric Vehicles

Forecasts of EVs were provided by S&P Global and their zonal forecasts take into account vehicle miles traveled (VMT), vehicle efficiency, and charging behavior in their hourly charging impacts. S&P Global uses federal, state, and metropolitan level data to produce their forecast. More information on the S&P Global electric vehicle forecast methodolgy and assumptions can be found under the November 27, 2023 Load Analysis Subcommittee materials[4].

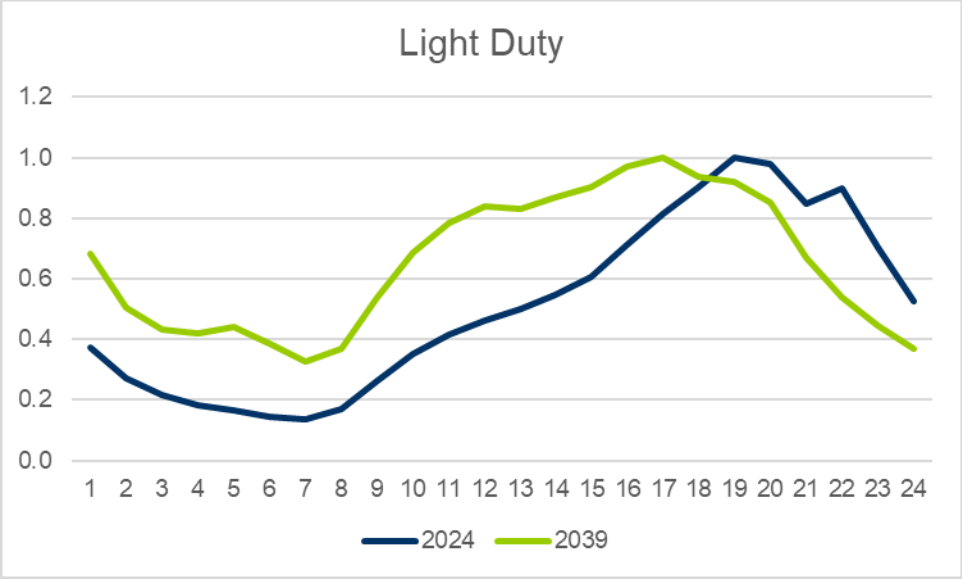
Charts below show vehicle counts for light duty electric vehicles by zone followed by medium & heavy duty electric vehicle counts by zone. The medium & hevy duty category contains delivery vans, school bus, transit bus, medium truck, short haul, and long haul vehicles.

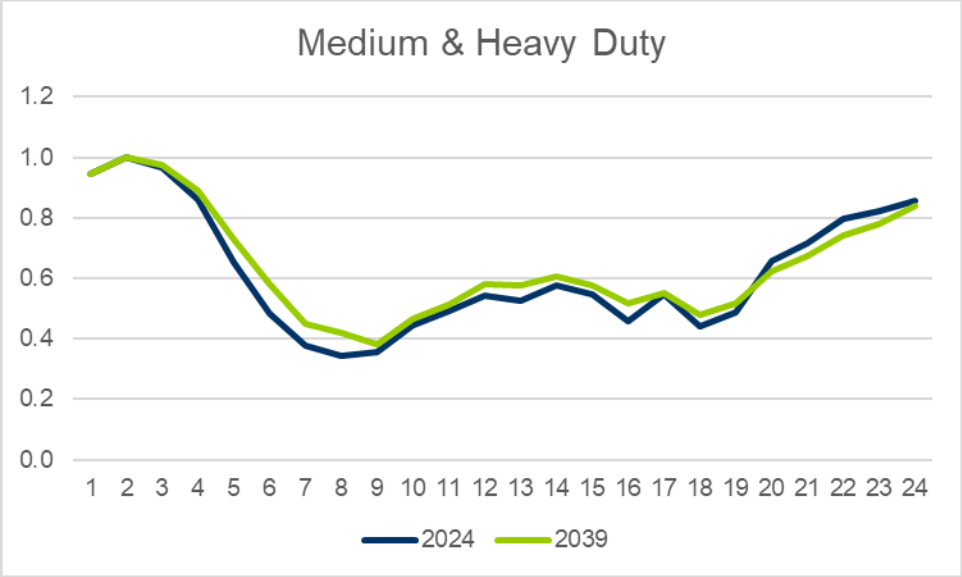


[4] https://www.pjm.com/-/media/committees-groups/subcommittees/las/2023/20231127/20231127-reference---12---spgci-consulting-methodology-and-assumptions---ev-forecast-.ashx



S&P Global provided an hourly charging impact for each zone throughout the forecast horizon. Below shows a total RTO average per-unitized charging shape from summer weekdays for light, medium, and heavy duty electric vehicles. The blue line is a charging shape for 2024 and the green line shows the per-unitized charging shape for 2039. For light duty electric vehicles, the 2024 charging shape shows more tendancy to charge later in the day around hour ending 17 – 20 while the 2039 charging shape shows more levelized charging throughout the day. The hourly charging shape for medium & heavy duty electric vehicles does not show a large shift in charging behavior due to the nature of these vehicles being out delivering goods, people, etc. during the day and then back to their depots at night to charge.





Behind-the-Meter Battery Storage Operation

As indicated above, the amount of behind-the-meter battery storage is based on a forecast from S&P Global. The methodology for their forecast is based on an attachment model (storage installed with solar), and thus are assumed to be used in conjunction with distributed solar. The assumption is made that batteries available to discharge at summer peak and thus subtract from loads on the summer peak distribution.

Exogenous Factors

PJM annually solicits information from its member Electric Distribution Companies (EDC) for large load shifts (either positive or negative) that are known to the EDC but may be unknown to PJM. Once the request has been verified

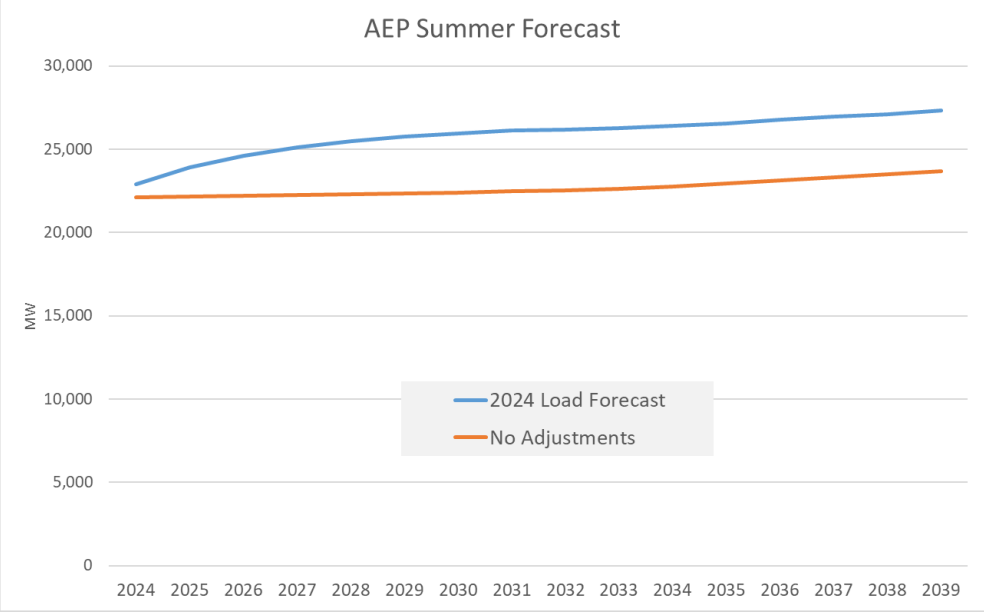
per the guidelines in Attachment B of Manual 19, PJM works towards accounting for it in its load forecast. Each request is considered on a case-by-case basis, with particular caution paid to avoid double-counting anticipated load increases or decreases. With each forecast adjustment, PJM quantifies the MW impact on the forecast that is due to this request.

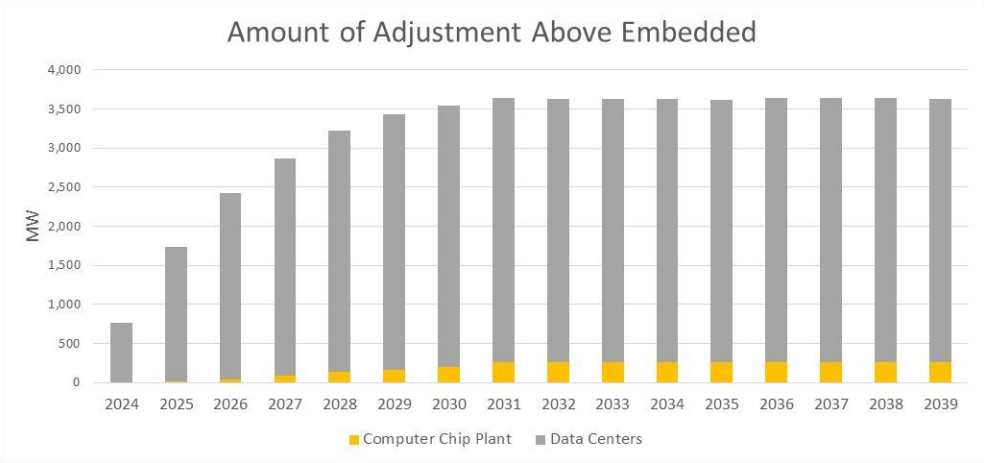
AEP – Data Centers and Computer Chip Plant

AEP requested that PJM consider load additions related to significant growth in data centers and a computer chip manufacturing site outside of Coumbus. AEP provided forecasted data center additions as well as historical cumulative data center information. Hourly information related to historical data center load was included in the data provided. PJM removed monthly data center load from the commercial EIA data in an effort to remove any double counting. PJM also removed hourly data center load from our historical loads that get used in our model estimation.

The computer chip plant will be a new facility so no historical data is available. PJM reviewed economic data for the computer chip plant and is using a percentage of their contract capacity.

The first chart below shows what the summer forecast would be for AEP without the adjustments in orange and with adjustments in blue. The bar chart at the bottom shows this amount above what is embedded in the forecast which is the difference between the blue and orange forecast lines.



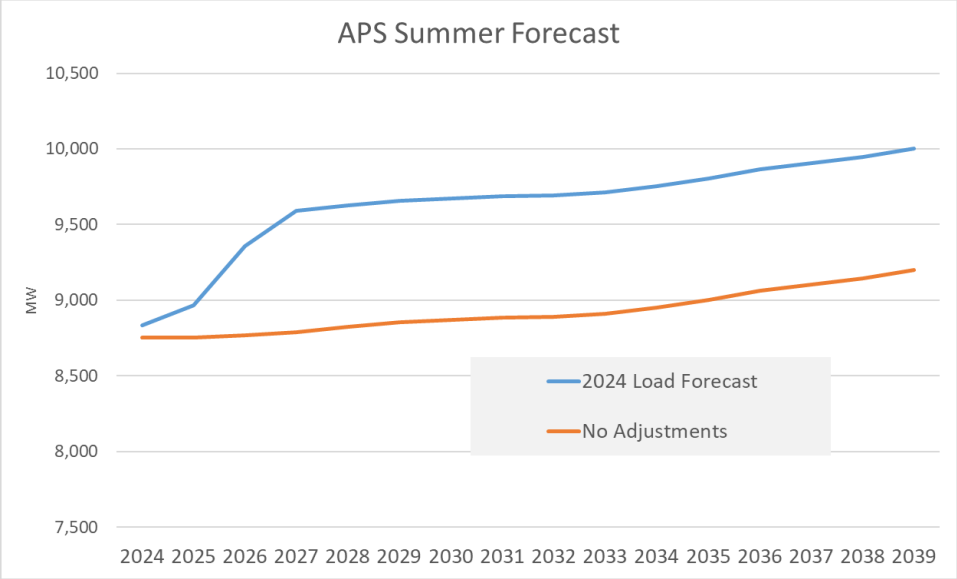


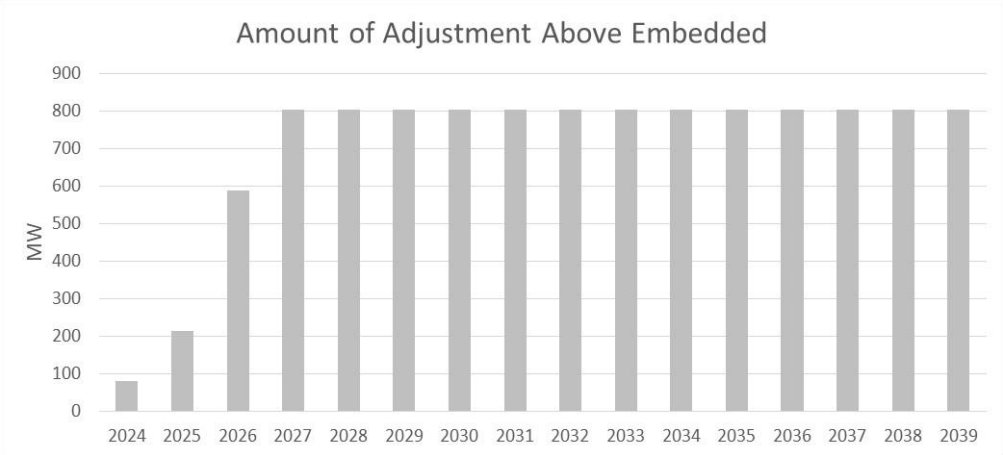
PJM had multiple meetings with AEP staff to discuss this adjustment, and it is anticipated that there might be more data center load forthcoming. PJM will continue to be in contact with AEP to understand these trends as they develop.

APS – Data Centers

First Energy requested PJM consider load additions related to significant growth in data centers. These sites are coming online and growing through mid-2027. The load is predominately due to a single site called Quantum Loophole. This site does not have load history as it is new so no adjustment to history was made. PJM reviewed commercial base load and observed declines through the forecast horizon[5]. Thus, PJM concluded that there is no embedded load due to data centers in APS. Below shows what the APS summer forecast would be without the adjustment and with the adjustment. The final adjustment is shown in the bar chart. PJM has been and will continue to be in contact with First Energy to follow this development.

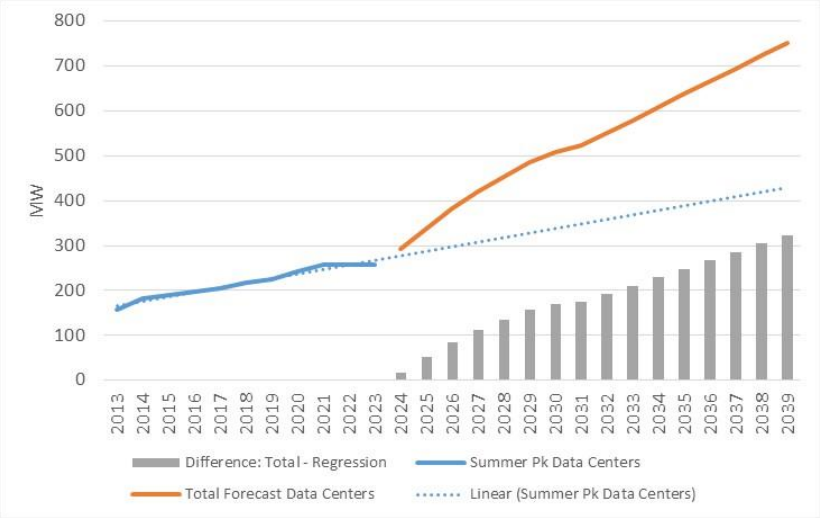
[5] See https://www.pjm.com/-/media/committees-groups/subcommittees/las/2023/20231127/20231127-reference---02---residential-commercial-industrial-sectors-and-indices.ashx



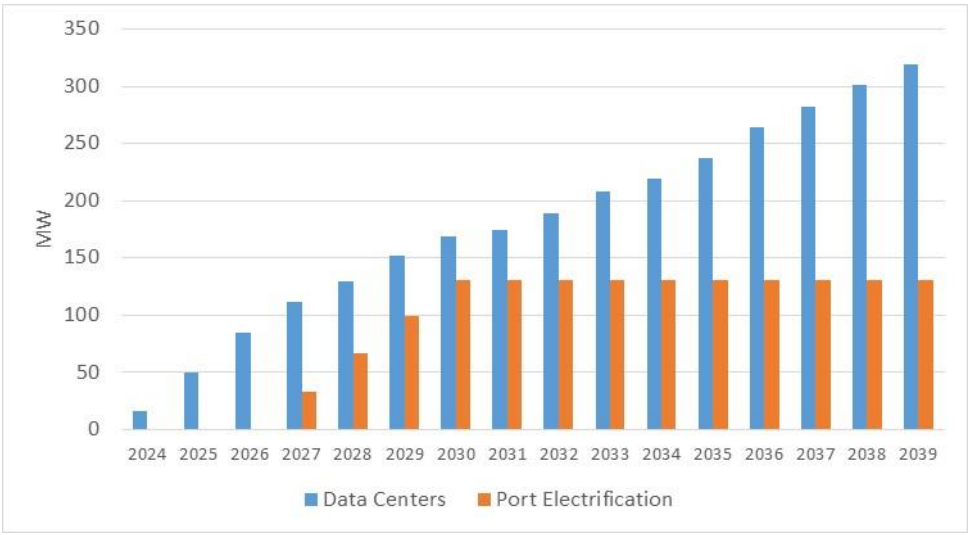


PS – Data Centers and Port Electrification

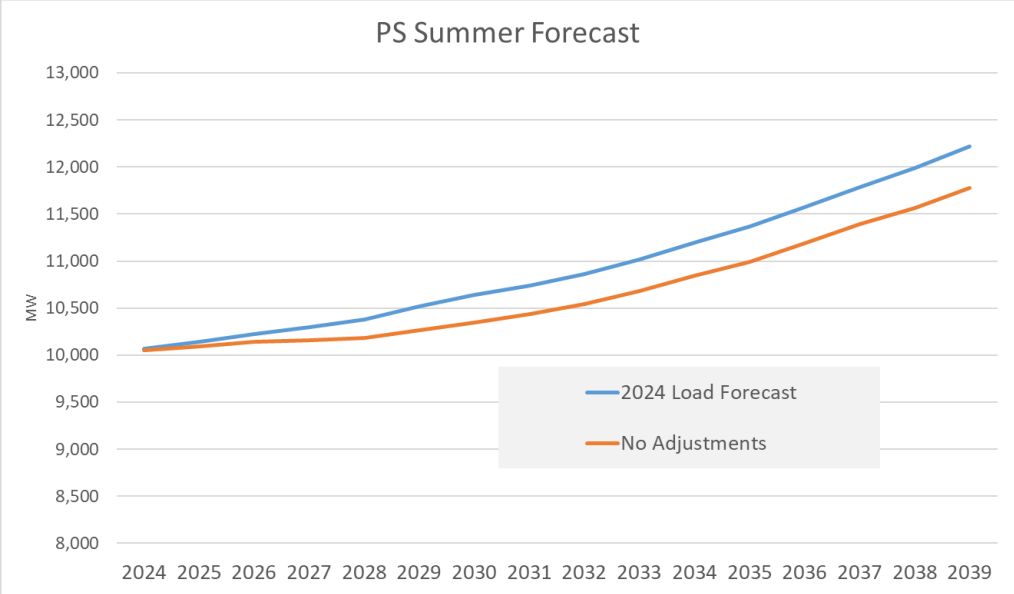
PS requested forecast adjustments for data center growth and port electrification. PS provided historical peak history back to 2013. Since we did not have hourly historical data for data centers to remove from history we did the following; created a trend with historical peaks (dotted blue line below), compared this trend with the total amount of data center load (existing and forecasted) that we received from PS (orange line below), calculated the difference as amount forecast is adjusted (grey bars below).

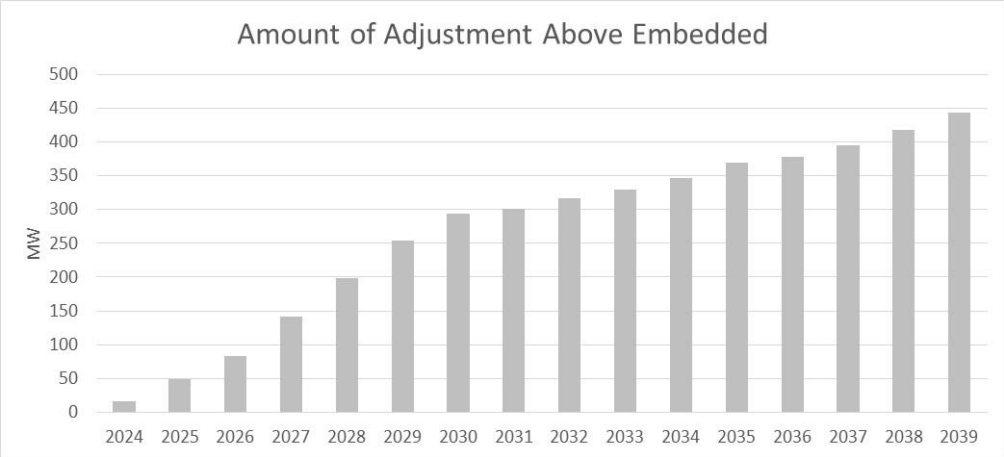


PS also submitted a request for port electrification at their Newark, Elizabeth, and Bayonne ports. The Inflation Reduction Act provides money to electify port equipment and docked ships. This load is forecasted to grow from 2027 to 2030 and then be constant.



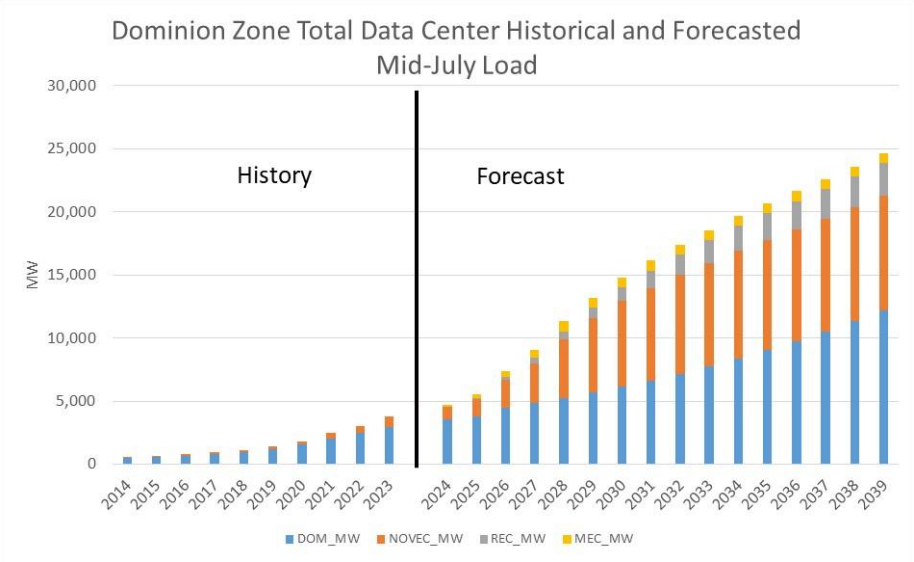
Below shows the PS summer forecast without the adjustments and with the adjustments. The final adjustment is shown in the bar chart. PJM has been and will continue to be in contact with PS to follow this development.





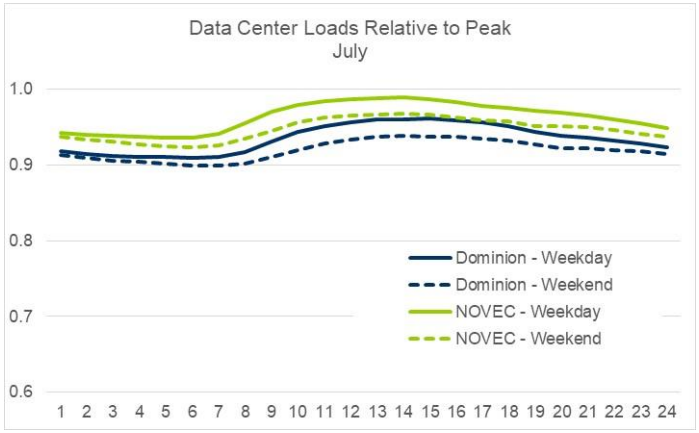
Dominion – Data Centers

Dominion requested that PJM consider a forecast adjustment to account for the growth of data centers in Virginia. This adjustment has been in place in some form since the 2014 Load Forecast Report. Dominion and Northern Virginia Electric Cooperative (NOVEC) provide PJM with historical hourly information as well as forecasted peak information for the next fifteen years. Dominion provided forecasted data center load for non-NOVEC cooperatives Mecklenburg (MEC) and Rappahannock (REC).



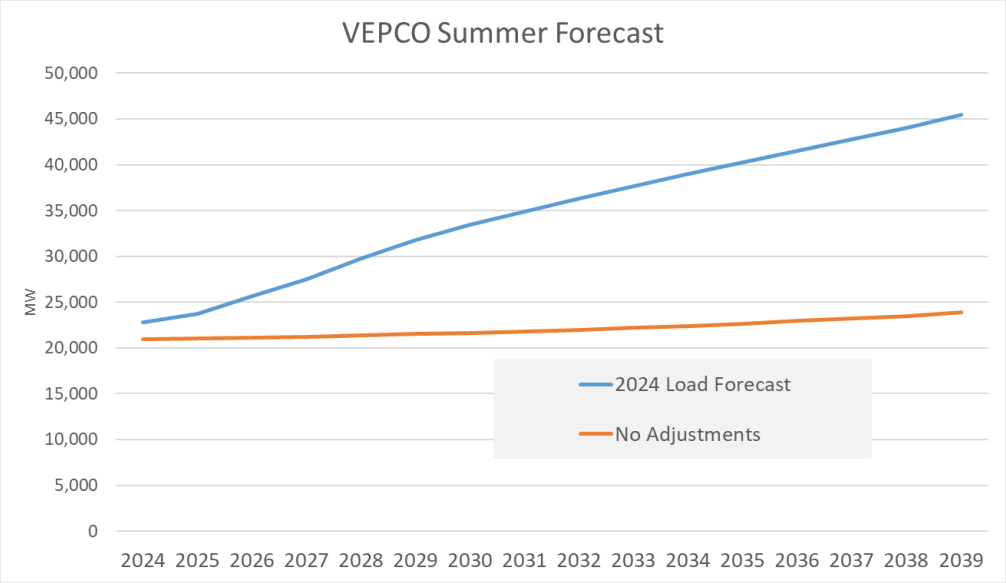
With the data provided, steps are taken to isolate the impact on the final forecast to mitigate double-counting concerns. Facility data is first removed from the historical data. This is done in both the historical hourly data used to feed the final load forecast model as well as the Commercial sector data used to help inform our understanding on usage trends.

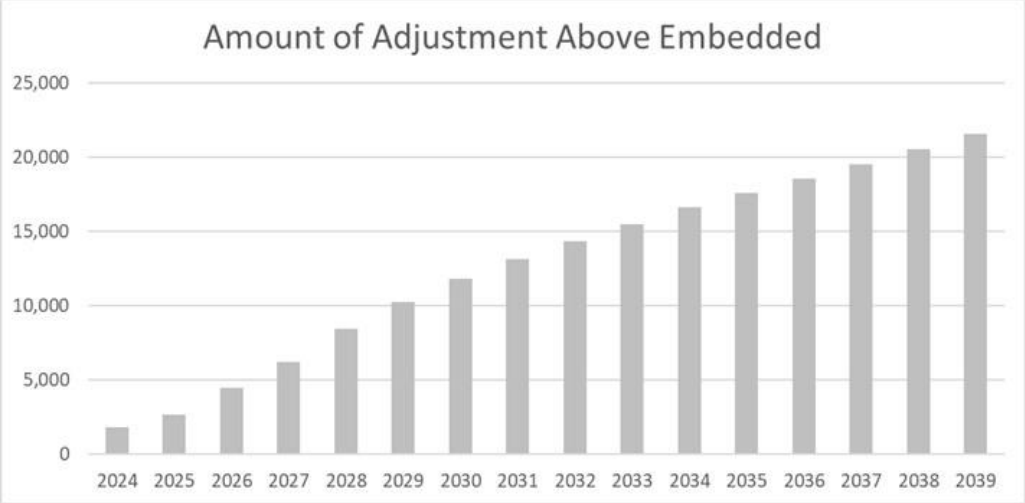
Given that we have hourly historical data center data and the PJM forecast model is hourly, forecasted hourly loads are derived. For each of Dominion and NOVEC, by month and weekday/weekend, historical hourly data center loads are calculated as a share of the provided monthly peaks. This provides us with a weekday and weekend shape that can be applied to the forecasted monthly peaks.



The final forecast needs to be re-constituted with the expected data center amount as the forecasted hourly loads coming from the model exclude data centers. Monthly peak amounts are combined with the calculated hourly shapes and these are added to the modeled forecast.

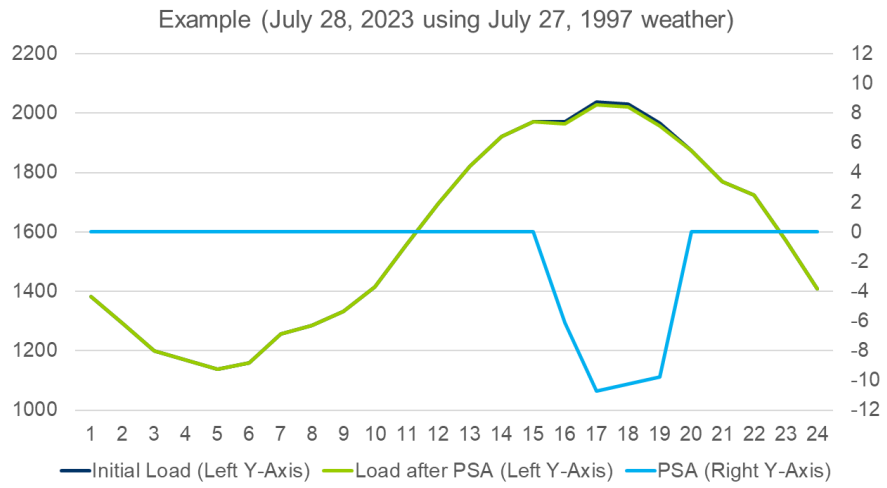
Below shows what the Dominion summer forecast would be without the adjustment and with the adjustment. The final adjustment for the Dominion zone is shown in the bar chart and shows the amount above what is embedded.





EKPC – Peak Shaving Adjustment

EKPC requested a peak shaving adjustment that began with the 2023 Delivery Year. EKPC provides PJM with weather triggers as well as program response matrixes for their three programs (smart thermostats, air conditioning switches, and water heater switches). In the forecast simulation process, on days that exceed the trigger, the programs are enacted. The chart below shows an example of program implementation in the forecast. On this day in the forecast, the program is triggered and reduces load in HE16 through HE19 resulting in a peak reduction of 10MW.



After summer 2023, PJM evaluated actual performance against expected performance and used this performance rating[6] in the 2024 Load Forecast.

NRBTMG to DR

PJM was notified of existing Non-Retail Behind-the-Meter Generation (NRBTMG) transitioning to participate as Demand Response starting in 2024. For the 2024 Load Forecast, these zones are adjusted upward to facilitate these resources' participation in RPM for a total of 21.2 MW.

- AEP: 8.7 MW
- ATSI: 1.6 MW
- DAYTON: 1.5 MW
- PPL: 2.9 MW
- PENLC: 0.5 MW
- DUKE: 6 MW

State Policy

The State Of New Jersey's Executive Order No. 316 is an executive order signed into law by Governor Phil Murphy on February 15th, 2023. The portion of the order that impacts PJM's long term load forecast is the goal that by December 31, 2030, 400,000 additional homes & 20,000 additional commercial spaces will be electrified. PJM incorporated this goal into our load forecast by modifying our end-use inputs for each zone in the state of New Jersey (AE, JCPL, PS, & RECO); specifically electric heating & electric water heating. We assumed that electrification of space heating means transitioning to electric heat pumps.

For both residential & commercial sectors, we added additional heat pumps & electric water heaters to our end-use forecast each year beginning in 2024. The total number of buildings with electric heating increases at a rate that

[6] https://www.pjm.com/-/media/documents/manuals/m19.ashx Attachment D

allows the 400,000/20,000 additional goal to be reached by 2030. This increased saturation of electric heating & water heating drives up the heating load for zones located in the state of New Jersey. This is primarily reflected in the winter peak forecast for these zones as there is not a large amount of heating load during the summer. The impacts of this goal on winter peak loads are easily noticeable when looking at the zonal waterfall charts comparing the 2023/2024 load forecasts for future delivery years. These charts are available on the Load Forecast Development Process page of PJM's website.

Additional Model Detail

Calendar Variables

The forecast model includes a number of variables to capture calendar effects, represented primarily as either binary variables or fuzzy binary variables. Binary variables take a value of 1 or 0, whereas fuzzy binary variables have values ranging from 0 to 1. There is also a graduated variable to take into account the effect of the week leading up to Christmas and the week after the New Year.

Day of Week (=1 when that day, 0 otherwise)

Monday	Tuesday	Wednesday	Thursday	Friday	Saturday

Month (=1 when that month, 0 otherwise) and DST variables:

Jan	Feb	Mar	MarDST	Apr	May	Jun
Jul	Aug	Sep	Oct	Nov	NovDST	

Holiday variables are coded such that they have values for more than one day, and for some holidays, these values can differ year to year depending on the day of the week the holiday is observed. These variables are included because generally these days would be expected to have lower than normal loads.

MLK	PresDay	MemDay	LaborDay

MLK (Martin Luther King Day), *PresDay* (Presidents' Day), *MemDay* (Memorial Day), and *LaborDay* (Labor Day)

	Value
Day before Holiday	0.2
On Holiday	1
All other days	0

GoodFri	Thanks

GoodFri (Good Friday) and *Thanks* (Thanksgiving Day)

	Value
On Holiday	1

All other days	0

July4th

July4th (Independence Day)

	Value by Day of Week						
	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Sunday
July 2	0.10	0.00	0.00	0.15	0.15	0.10	0.15
July 3	0.70	0.25	0.15	0.20	0.80	0.20	0.20
July 4	1.00	1.00	0.80	1.00	1.00	0.40	0.30
July 5	0.80	0.15	0.15	0.25	0.70	0.30	0.15
July 6	0.00	0.00	0.00	0.00	0.10	0.20	0.00
All other days	0.00	0.00	0.00	0.00	0.00	0.00	0.00

FriAThanks

FriAThanks (After Thanksgiving Day)

	Value
On Holiday	1
Day After	0.2
All other days	0

WkBeforeXMas

WkAfterNewYear

WkBeforeXMas(If day is weekday before Christmas Day)

	Value if Weekday
December 18	0.14
December 19	0.29
December 20	0.43
December 21	0.57
December 22	0.71
December 23	0.86
December 24	1
All other days	0

WkAfterNewYear(If day is weekday after New Year)

	Value
January 1	1.14
January 2	1.00
January 3	0.86
January 4	0.71
January 5	0.57
January 6	0.43
January 7	0.29
January 8	0.14
All other days	0

XMasEve

XmasEve (Christmas Eve)

	Value by Day of Week						
	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Sunday
December 24	1.00	1.00	0.80	0.67	1.00	0.50	0.33
All other days	0.00	0.00	0.00	0.00	0.00	0.00	0.00

XMasDay

XMasDay (Christmas Day)

	Value by Day of Week						
	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Sunday
December 25	1.00	1.00	1.00	1.00	1.00	0.50	0.50
All other days	0.00	0.00	0.00	0.00	0.00	0.00	0.00

NYEve

NYEve (New Year's Eve)

	Value by Day of Week						
	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Sunday
December 31	0.8	0.8	0.8	0.8	1.0	0.4	0.4
All other days	0.0	0.0	0.0	0.0	0.0	0.0	0.0

NYDay

NYDay (New Year's Day)

	Value by Day of Week						
	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Sunday
January 1	1.0	1.0	1.0	1.0	1.0	0.5	0.4
All other days	0.0	0.0	0.0	0.0	0.0	0.0	0.0

WkDayBeforeHol WkDayAfterHol

WkDayBeforeHol (weekday before Holiday)

	Value (if Weekday)
Day Before Holiday	1.00
All other days	0.00

WkDayAfterHol(weekday after Holiday)

	Value (if Weekday)
Day After Holiday	1.00
All other days	0.00

Monthly Walk variables are graduated variables that start at 1 on the first day of the month and increase by 1 each day until the last day of the month to capture any potential inter-month trends.

JanWalk	FebWalk	MarWalk	AprWalk	MayWalk	JunWalk
JulWalk	AugWalk	SepWalk	OctWalk	NovWalk	DecWalk

Zonal End-Use Variable Calibration

The Energy Information Administration's (EIA) 2023 Annual Energy Outlook Reference Case is the starting point for data on residential end-uses. Residential end-uses fall into categories, which are then grouped according to weather and non-weather sensitive use types (i.e. Heating, Cooling, and Other). These categories are expressed as saturation rates (% of customers), efficiency metrics (use per year or efficiency term like Seasonal Energy Efficiency Ratio), and intensities (kWh per customer per year). Categories and groupings are as follows:

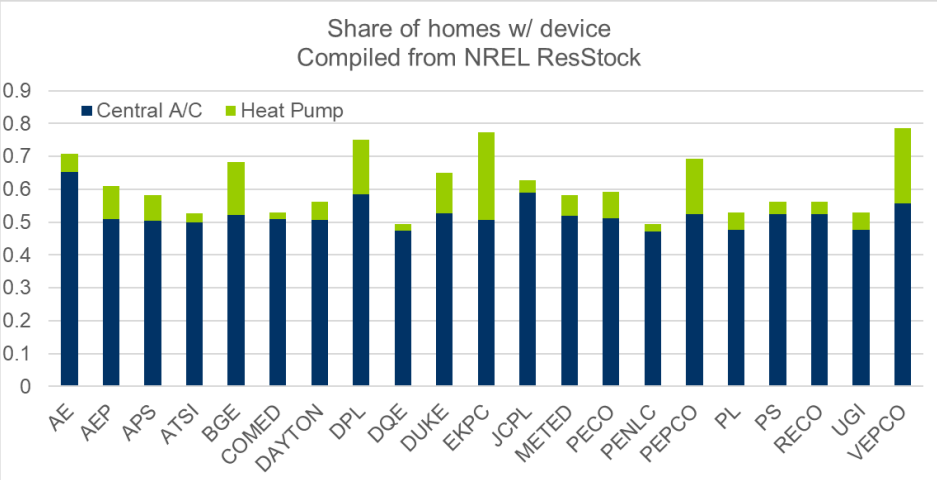
- Heating
  - Electric furnace and resistant room space heaters
  - Heat pump space heating
  - Ground-source heat pump space heating
  - Secondary heating
  - Furnace fans
- Cooling
  - Central air conditioning
  - Heat pump space cooling
  - Ground-source heat pump space cooling
  - Room air conditioners
- Other
  - Electric water heating
  - Electric cooking
  - Refrigerator
  - Second refrigerator
  - Freezer
  - Dishwasher
  - Electric clothes washer
  - Electric clothes dryer
  - TV sets
  - Lighting
  - Miscellaneous electric appliances

PJM receives this data at the Census division level through membership in Itron's Energy Forecasting Group. PJM then supplements this with two pieces of information:

- Zonal saturation and intensity data from NREL ResStock[7]
- Zonal saturation estimates from:
  - American Electric Power – all appliance categories through 2021
  - Allegheny Power – all appliance categories through 2016
  - American Transmission Systems, Inc. – all appliance categories through 2016
  - Commonwealth Edison – all appliance categories for 2019
  - Duke Energy Ohio and Kentucky – all appliance categories through 2014
  - East Kentucky Power Cooperative – Heat Pumps for Heating and Cooling, Electric Furnaces, Secondary Heating (Room Heating), Central A/C, Room Air Conditioners, and Water Heaters through 2013
  - Jersey Central Power & Light – all appliance categories through 2016
  - Metropolitan Edison – all appliance categories through 2016
  - Pennsylvania Electric – all appliance categories through 2016
  - Dominion Virginia Power – Heat Pumps for Cooling, Central A/C and Room Air Conditioners through 2014

[7] https://resstock.nrel.gov/

Data from NREL ResStock is used to calibrate zones for 2018 to help provide granularity across PJM. Zones are mapped to counties, and then PJM uses the ResStock database to provide customized data at the zonal level on appliance saturations, appliance intensities, and average home sizes[8]. The below chart displays some of the information gleaned from this exercise on central cooling.

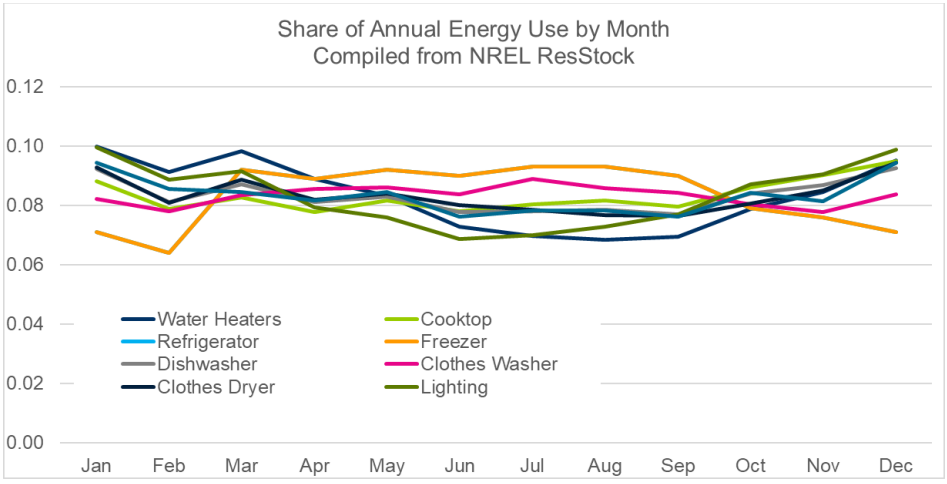


Resulting data is then aligned with zonal-supplied historical appliance saturation rates. Zones are subsequently assigned to Census Divisions for driving the forecasts. This process allows the forecast to be influenced by the historical relative mix of appliances. The below table shows the mapping of Zones to Census Divisions.

[8] In the case of RECO and UGI, this exercise yielded an insufficient sample size according to guidelines laid out by NREL for using their data. PS and PL were used, respectively, in this case.

Zone	Census Division
AE	Middle Atlantic
AEP	East North Central
APS	South Atlantic
ATSI	East North Central
BGE	South Atlantic
COMED	East North Central
DAYTON	East North Central
DPL	South Atlantic
DQE	Middle Atlantic
DUKE	East North Central
EKPC	East South Central
JCPL	Middle Atlantic
METED	Middle Atlantic
PECO	Middle Atlantic
PENLC	Middle Atlantic
PEPCO	Middle Atlantic
PL	Middle Atlantic
PS	Middle Atlantic
RECO	Middle Atlantic
UGI	Middle Atlantic
VEPCO	South Atlantic

Finally, monthly non-weather sensitive shapes are calculated from the NREL ResStock data as well. These are used to shape the end-use intensity variables used in the monthly Residential Average Use model. These can be seen below.



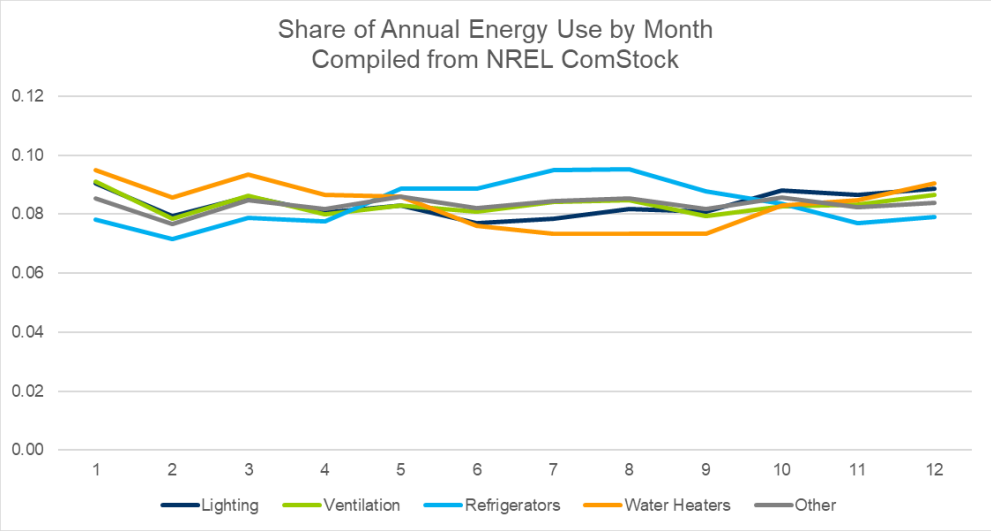
Commercial

The EIA's 2023 Annual Energy Outlook Reference Case is the starting point for data on commercial end-uses. Commercial end-uses fall into categories, which are then grouped according to weather and non-weather sensitive

use types (i.e., Heating, Cooling, and Other). These categories are expressed as intensities (kWh per square foot per year). These categories and groupings are as follows:

- Heating
- Cooling
- Other
    - Ventilation
    - Water Heating
    - Cooking
    - Refrigeration
    - Lighting
    - Office Equipment
    - Miscellaneous

PJM receives this data at the Census Division level through membership in Itron's Energy Forecasting Group, and zones are assigned to Census Divisions using the same mapping as used for Residential end-uses. Like with Residential, NREL has also developed ComStock[9]. Monthly non-weather sensitive shapes are calculated from the NREL ComStock data. These are used to shape the end-use intensity variables used in the monthly Commercial Use model. These can be seen below.



Economics Zonal Geographic Assignment

Economic variables come from Moody's Analytics and geographical areas are assigned to zones per the table below.

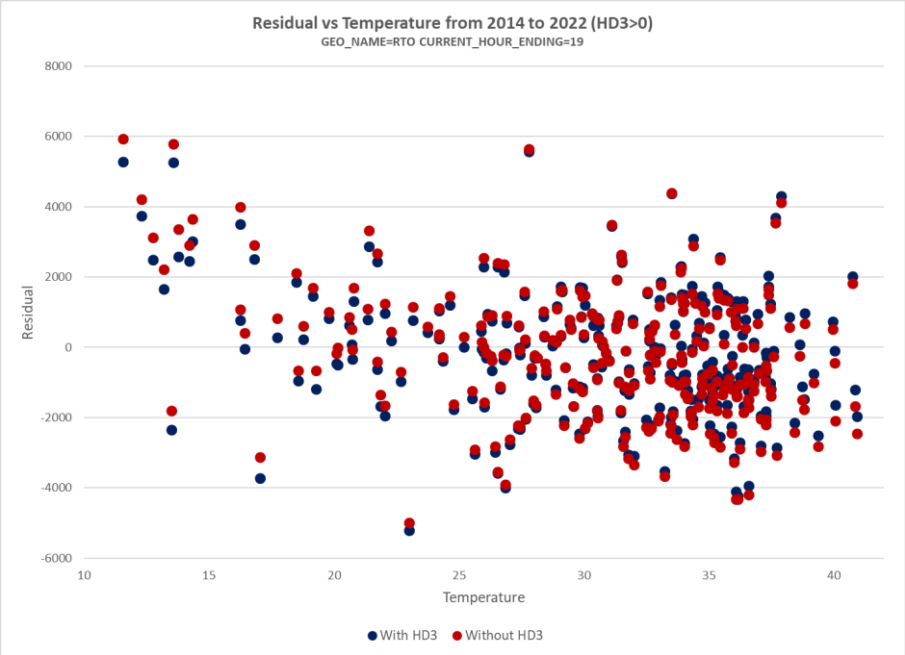
[9] https://comstock.nrel.gov/

Zone	Metro Area Name(s) or State
AE	Atlantic City-Hammonton NJ, Ocean City NJ, Vineland-Bridgeton NJ
AEP	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
APS	Cumberland MD-WV, Hagerstown-Martinsburg MD-WV, Chambersburg-Waynesboro PA, State College PA, Winchester VA-WV, Morgantown WV, Parkersburg-Vienna WV
ATSI	Akron OH, Cleveland-Elyria OH, Mansfield OH, Springfield OH, Toledo OH, Youngstown-Warren-Boardman OH-PA, Pittsburgh PA
BGE	Baltimore-Columbia-Towson MD
COMED	Chicago-Naperville-Arlington Heights IL, Elgin IL, Kankakee IL, Lake County-Kenosha County IL-WI, Rockford IL
DAY	Dayton OH
DEOK	Cincinnati OH-KY-IN
DLCO	Pittsburgh PA
DOM	Virginia
DPL	Dover DE, Wilmington DE-MD-NJ, Salisbury MD-DE
EKPC	Cincinnati OH-KY-IN, Louisville/Jefferson County KY-IN, Elizabethtown-Fort Knox KY, Bowling Green KY, Lexington-Fayette KY, Huntington-Ashland WV-KY-OH
JCPL	Camden NJ, Newark NJ-PA, Trenton NJ
METED	Allentown-Bethlehem-Easton PA-NJ, East Stroudsburg PA, Gettysburg PA, Lebanon PA, Reading PA, York-Hanover PA,
PECO	Montgomery County-Bucks County-Chester County PA, Philadelphia PA
PENLC	Altoona PA, Erie PA, Johnstown PA
PEPCO	Washington D.C., California-Lexington Park MD
PL	Allentown-Bethlehem-Easton PA, Bloomsburg-Berwick PA, East Stroudsburg PA, Harrisburg-Carlisle PA, Lancaster PA, Scranton-Wilkes-Barre-Hazleton PA, Williamsport PA
PS	Camden NJ, Newark NJ-PA, Trenton NJ
RECO	Newark NJ-PA
UGI	Scranton-Wilkes-Barre-Hazleton PA

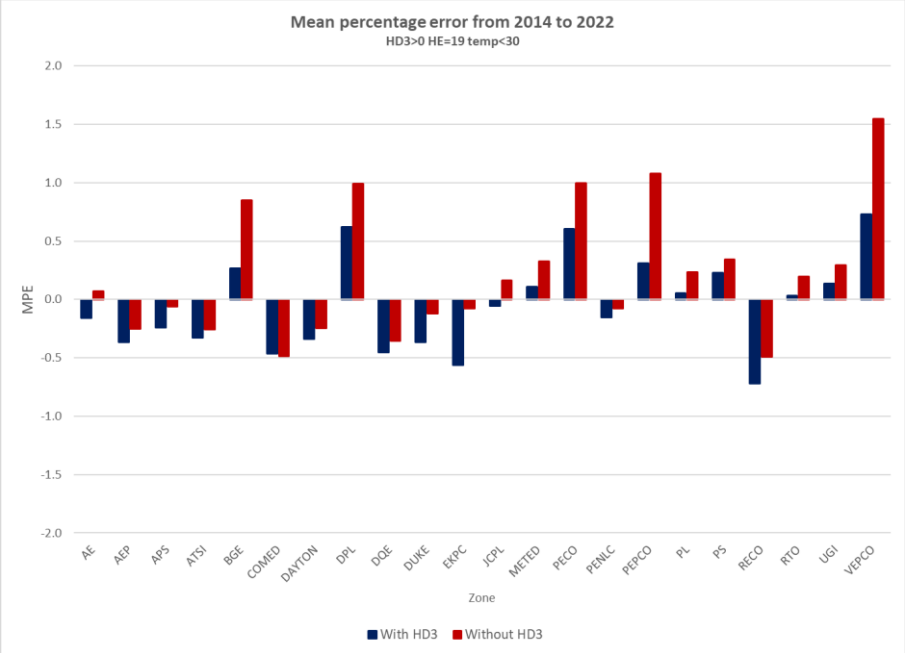
Addition of HD3 Variable

A new variable HD3 has been added to our model to reflect the relationship of load to cold weather conditions. As stated earlier in the document, HD3 is an additional spline in the heating season (15 degrees off the hourly base point). This additional variable provides symmetry with the cooling season (TD1 through TD3 variables) and helps to address potential for underfit at colder temperatures such as during Winter Storm Elliott.

The following charts help explain the rationale for HD3's inclusion. This first chart is of RTO residuals for HE19 and shows that inclusion of this variable helps to reduce some under-fit at very low temperatures.



This next chart demonstrates zonal performance, MPE (mean percentage error) values for model with HD3 showed improvement in several noticeable zones that had previously shown more tendency to under-fit when the temperature is below 30°F.



We conclude that the addition of the new cold weather variable has improved our model, and we will continue to investigate whether further modifications may be warranted.

EXHIBIT NO. 46

Itron
20 Park Plaza, 4th Floor
Boston, MA 02116
(617) 423-7660

2022 PJM MODEL REVIEW

FINAL REPORT



Prepared For:

PJM

Prepared By:

Eric Fox, Senior Forecast Consultant
Michael Russo, Forecast Consultant
Dr. Frank A. Monforte, Senior Forecast Consultant
Dr. Stuart McMenamin, Managing Director

TABLE OF CONTENTS

1 OVERVIEW 1

2 REVIEW OF THE CURRENT PJM MODEL 3

3 LONG-TERM MODEL DRIVERS 7

TRANSITION FROM ANNUAL TO MONTHLY SECTOR MODELS 11

ESTIMATE RATE CLASS MODELS 12

SYSTEM END-USE MODEL INPUT CONSTRUCTION 16

4 HOURLY MODEL ANALYSIS AND RECOMMENDATIONS 22

EXAMPLE OF HOURLY LOAD DATA 22

EXAMPLE OF HOURLY WEATHER DATA 24

HOURLY MODELS 25

TRANSFORMING HOURLY WEATHER 26

ROLLING TWO-PART MODEL: EXPLANATORY FACTOR CASCADE 31

TEMPERATURE-HUMIDITY INDEX CONSTRUCTION 32

WIND/TEMPERATURE INTERACTIONS 33

CLOUD COVER/TEMPERATURE INTERACTIONS 35

INTERACTING HOURLY MODEL VARIABLES WITH SAE EXPLANATORY FACTORS 36

PEAK DAY PREDICTED VALUES AND POST PROCESSING 38

MODEL TESTING 41

5 RESHAPING DEMAND: MODELING TECHNOLOGY IMPACTS 42

EXTENDED WEATHER SIMULATION FRAMEWORK 42

6 MODELING ISSUES 46

MEASURING FORECAST ACCURACY 46

WEATHER NORMALIZATION 47

CAPTURING THE IMPACTS OF ENERGY EFFICIENCY PROGRAMS 48

ACCOUNTING FOR TEMPERATURE TRENDS 49

LARGE LOAD ADJUSTMENTS 51

7 RECOMMENDATIONS 53

LIST OF FIGURES

Figure 2-1: LTFS 2022 Model Framework 5

Figure 2-2: 2022 Map of PJM Participating EDCs 6

Figure 2-3: Configuring Weather Simulation Forecast Traces 6

Figure 3-1: Forecast Census Divisions 8

Figure 3-2: South Atlantic End-Use Intensities 9

Figure 3-3: Total Residential Intensities 10

Figure 3-4: South Atlantic Commercial End-Use Intensities 10

Figure 3-5: Total Commercial Intensities 11

Figure 3-6: Residential SAE average use Model 12

Figure 3-7: Commercial SAE Sales 13

Figure 3-8: DPL Residential SAE Model 14

Figure 3-9: DPL Commercial SAE Model 15

Figure 3-10: DPL Industrial Sales Model 16

Figure 3-11: DPL Residential End-Use Energy Requirements (MWh) 17

Figure 3-12: DPL C&I End-Use Energy Requirements (MWh) 18

Figure 3-13: DPL Total End-Use Energy Requirements (MWh) 19

Figure 3-14: DPL Daily Inputs for Hourly Zonal Models 20

Figure 3-15: DPL Hourly base-use energy requirements (2027) 20

Figure 3-16: DPL BaseIdx 2025 - 2027 21

Figure 4-1: DPL Hourly Usage, Load, and BTM Solar – August 2021 23

Figure 4-2: Hourly Weather data for DPL Zone – August 2021 24

Figure 4-3: Scatter Plots for HE07 and HE18 – 2017 to 2021 26

Figure 4-4: Estimation Hourly MAPE Statistics – Comparison of Methods 30

Figure 4-5: Rolling Two-Part Model, Explanatory Factor Cascade Statistics 31

Figure 4-6: THI Formulas and HE17 Scatter Plots 32

Figure 4-7: Impact of Wind Variables on Model Accuracy 34

Figure 4-8: Impact of Cloud Variables on Model Accuracy 36

Figure 4-9: Example of Estimated Model (HE18) 37
Figure 4-10: Hourly Model Results – Summer 2021 NCP 38
Figure 4-11: Hourly Model Results – Summer 2021 CP 39
Figure 4-12: NCP and CP Hour Weather 39
Figure 4-13: Statistics for 2021 Summer CP Coincidence Factor 40
Figure 4-14: Hourly Model Results – Winter 2021 NCP and CP 40
Figure 4-15: Hourly Model Results – Winter 2021 NCP and CP 41
Figure 5-1: Example PDF of Reconstituted Loads for a Single EDC and Forecast Year 43
Figure 5-2: Example Solar PV Generation on Net Loads for a Single EDC 44
Figure 5-3: Example of EV Charging Impact on Net Loads for a Single EDC 45
Figure 6-1: DPL Average Temperature Trend 50
Figure 6-2: DPL Trended CDD 50
Figure 6-3: DPL Trended HDD 51

1 OVERVIEW

Itron, Inc. (Itron) was contracted by PJM to review the current forecast models and develop a set of recommendations for transitioning to an hourly forecasting framework. This report discusses the forecast, recommendations, and addresses issues raised by the PJM Market Participants.

Over the last three months, Itron has worked closely with PJM forecast staff in reviewing current forecast approach, identifying forecast issues, and developing new models for evaluation and ultimately a set of recommendations for the next phase of model improvements. The core task is to transition from daily peak and energy models to hourly models where the need for hourly long-term models is driven by the penetration of new technologies that are either currently or are expected to reshape system hourly loads.

Each year, PJM updates long-term energy and demand forecast for 22 Planning Zones (EDC) that are mapped into 6 Load Deliverability Areas (LDA). PJM faces a unique and complex forecasting problem as the PJM service area stretches across a large section of the country that includes utilities from Chicago to Philadelphia. Planning Zones are spread across different time zones, include different mixes of residential, commercial, and industrial customers, and at any one point in time, significant differences in weather conditions. All this must be pulled together to not only generate load forecasts for individual zones, but for the entire PJM system.

The current approach entails estimating a set of daily energy, own-peak, and coincident peak models for each zone and simulating with historical zonal daily weather data. Simulation results are combined across zones with the system forecast based on the 50% (expected case) outcome. Model-based zone peaks and coincident peaks are then exogenously adjusted for solar demand, electric vehicles, battery storage, and zone-specific load impact programs and large changes in industrial loads including data centers. The problem is a forecast based on daily demand models implicitly assumes the timing of the peak is constant over time. This is a relative safe assumption when factors that potentially reshape loads are small. But this is no longer the case; the projected impact of electric vehicles, increase in solar load, battery storage, and other programs designed to address climate change will significantly reshape loads impacting both the level and timing of system peak demand. The only means to address the issue is to transition to hourly load modeling framework that still addresses the weather, time zones, and customer diversity across the PJM Zones.

The report is organized into the following sections:

1. Overview
2. Review of the Current PJM Model
3. Developing the Long-Term Model Drivers
4. Hourly Model Analysis and Recommendations
5. Reshaping Demand – Modeling Technology Impacts
6. Other Issues
    - Measuring Forecast Accuracy
    - Weather Normalization
    - Impact of State and Utility Energy Efficiency Programs
    - Capturing Temperature Trends
7. Recommendations

2 REVIEW OF THE CURRENT PJM MODEL

PJM's current Long-term Forecast System (LTFS) is presented in Figure 2-1. The current PJM modeling process includes three sets of daily models for each zone. These are daily energy, daily noncoincident zone peak (NCP), and daily CP (zone load at the time of the daily PJM peak). For each zone, CP models are estimated for daily loads coincident with the Locational Deliverability Area (LDA) peak and coincident with the overall PJM system peak. The LTFS gathers the data required to estimate and forecast the load zone models, estimates the models, and then develops long-term forecasts using a multi-year weather simulation approach. The LTFS is a SAS™ based software solution that can be summarized into four major sections. For a detailed description of the current LTFS see **2022 Load Forecast Supplement**, PJM Resource Adequacy Planning Department, January 2022 (https://www.pjm.com/-/media/planning/res-adeq/load-forecast/load-forecast-supplement.ashx)

Data Input Section. The data inputs that feed the LTFS come in a variety of electronic formats. This section prepares the raw input data to be ingested by the Data Transformation Section of the LTFS. Data inputs include:

- Economic history and forecasts,
- End-use saturation and efficiency trends (SAE),
- Sector (residential, commercial, and industrial) sales (MWh) by EDC,
- Hourly Loads by EDC,
- Weather data by weather station, and
- Solar PV, EV Charging, Battery Storage, and Demand Response peak demand impacts.

Data Transformation Section. This section converts the raw input into daily coincident and non-coincident model variables. Key modules within this section are:

Sector Models. This series of three modules – Residential, Commercial, Industrial – are used to combine historical and forecasted economic data, end-use appliance saturation and efficiency trends, and annual sector sales to construct Space Heating, Space Cooling, and Other Non-Weather sensitive load indices that are used to drive long-term coincident and non-coincident peak forecasts by Electric Distribution Company (EDC). Figure 2-2 shows a map of the EDCs that make up the PJM control region. The Space Heating index is combined with daily Heating Degree Days to form an estimate of daily space heating load (MWh). The Space Cooling index is combined with daily Cooling Degree Days to form an estimate of historical and forecasted daily space cooling load (MWh).

Historical Load & Weather Data. Hourly historical load & weather data by EDC and weather station are input into the LTFS. The non-weather sensitive portion of the load is extracted from these data and is used to scale the Other Non-Weather sensitive load index to daily MWh for both the historical and forecast period.

Reconstituted Coincident and Non-Coincident Peak Loads. To account for load loss due to embedded solar PV generation, historical estimates of aggregate embedded solar PV generation for

each hour is added to the historical coincident and non-coincident peak loads that are computed directly from the historical measured load data with estimates of demand response added back. The coincident and non-coincident peak forecasts are then adjusted downward in the forecast period by subtracting off forecasted embedded solar generation values for hour ending 17:00.

Model and Forecast Engines Section. This section is used to specify and estimate the Daily Energy, and Coincident and Non-Coincident Peak Models by EDC. The second module generates the long-term daily energy, and coincident and non-coincident peak forecasts by EDC and Weather Simulation trace.

Daily Energy, and Coincident and Non-Coincident Peak Models. The Space Heating and Space Cooling indices are combined with historical Heating Degree and Cooling Day variables to form MWh estimates of daily space heating and cooling. The daily values are included along with the estimated Other Non-Weather sensitive load data as explanatory variables in a Daily Coincident Peak and Daily Non-Coincident Peak models. A separate set of Coincident and Non-Coincident Peak models is estimated for each EDC using the EDC specific daily Heating MWh, Cooling MWh, and Other MWh values.

Weather Simulations. To account for the geographical and temporal diversity of the large PJM operating footprint weather simulations are used to generate a distribution of daily coincident and non-coincident peak day forecasts for each EDC. The weather simulations use historical hourly weather data by weather station to form forecasts of daily Heating Degree Days and Cooling Degree days by EDC. The setup of the weather simulation traces is depicted in Figure 2-3. Each year of historical weather data is used to construct 13 separate load forecasts for each year in the forecast horizon. The 2022 vintage of the LTFS utilizes 27 years of historical weather data that drives 351 (computed as 13 x 27) daily load forecasts by EDC and year in the forecast horizon. Using the 351 forecast simulations, the LTFS constructed Cumulative Frequency Distributions of Coincident and Non-Coincident Peak Loads by Month/Season and EDC. The Cumulative Frequency Distributions are used to select load bands under design conditions (e.g., 50%, 10%, 90%). Advantages of the weather simulation framework are:

- Actual and Consistent Weather Patterns Across EDCs. Actual weather data for all weather stations are rotated together ensuring consistent and realistic weather patterns are used to drive the load forecasts.
- Consistency Across Weather Concepts. All weather concepts are rotated together ensuring consistent and realistic movements in temperatures, humidity, wind speed, wind direction, cloud cover, and solar irradiance. This is critical to align HVAC and solar PV generation interactions.

Forecast Adjustments. At the end of each weather simulation embedded Solar PV, EV Charging, and other technology impacts are applied to the coincident and non-coincident peak forecasts. The last step is to make adjustments for expected distribution system capacity projects that are not captured by the base case load forecast process.

Forecast Summary Report Module. This section is used to create formal and ad hoc summaries of the long-term forecasts.

FIGURE 2-1: LTFS 2022 MODEL FRAMEWORK

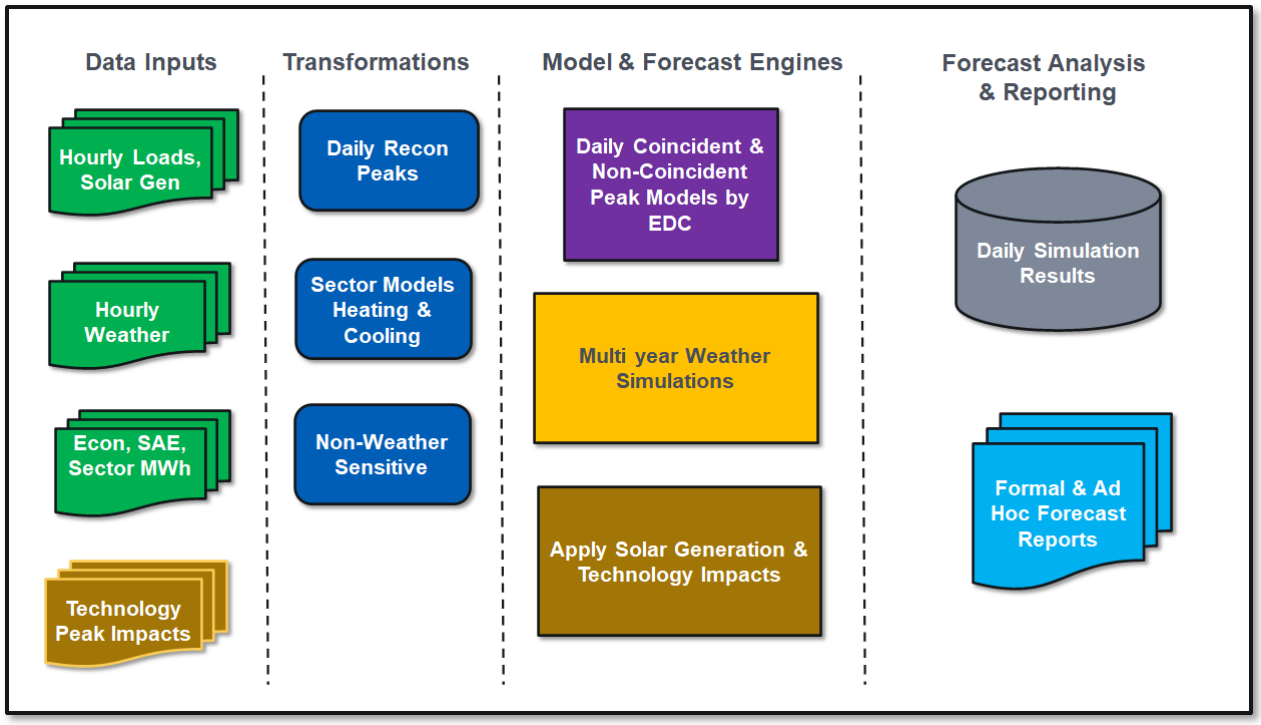


FIGURE 2-2: 2022 MAP OF PJM PARTICIPATING EDCS

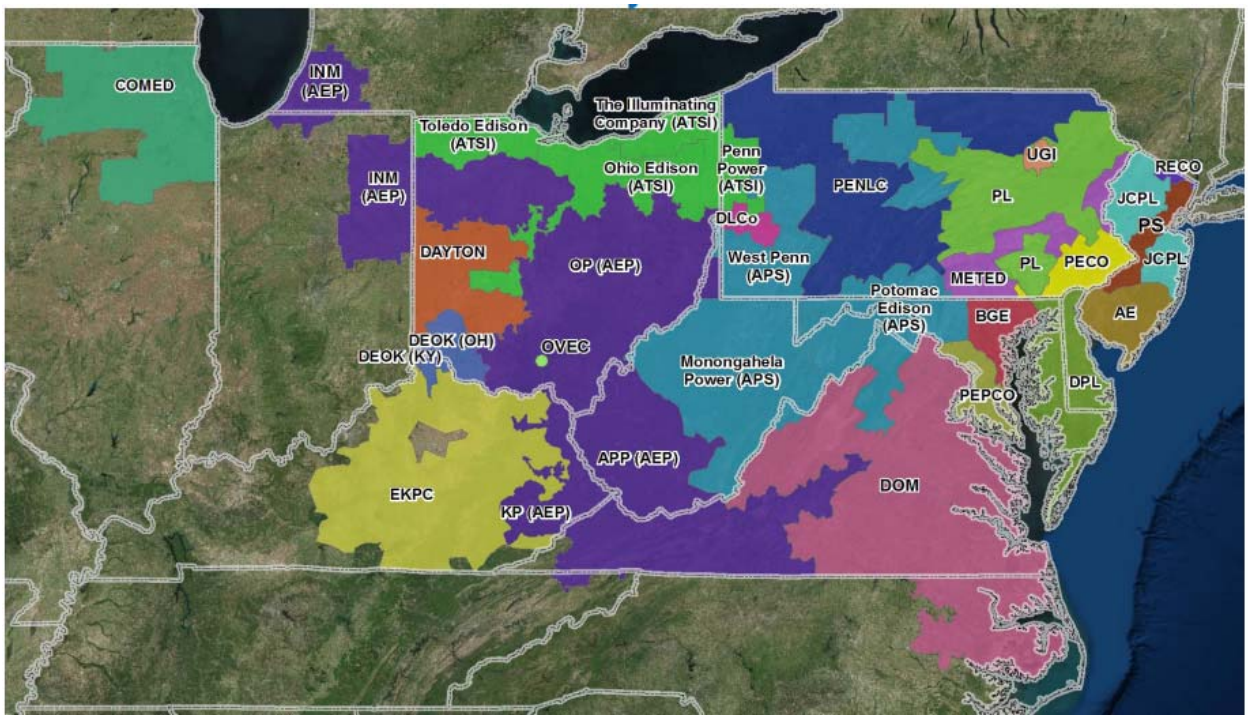


FIGURE 2-3: CONFIGURING WEATHER SIMULATION FORECAST TRACES

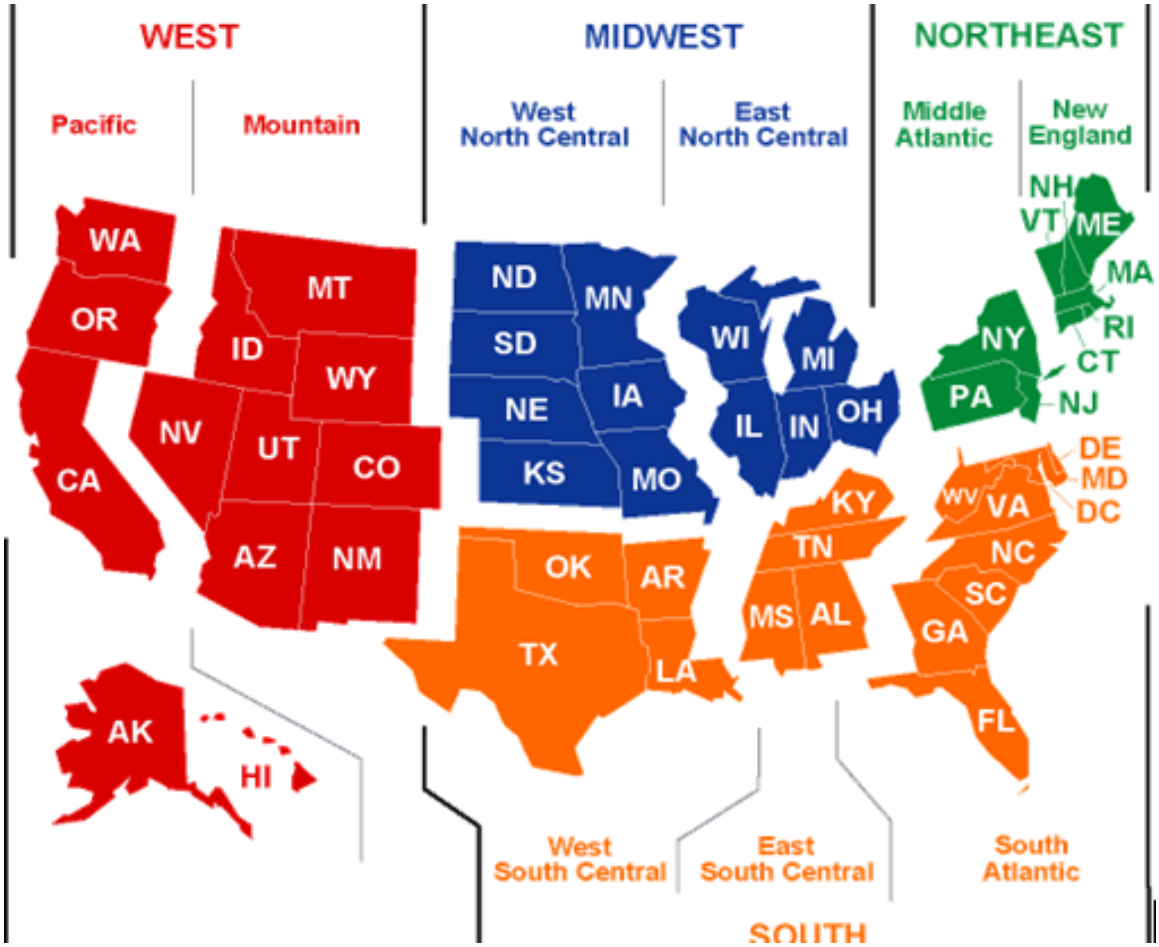
	Weather Scenarios												
		Rotate Forward						Rotate Backward					
Date	A1995	B1995	C1995	D1995	E1995	F1995	G1995	H1995	I1995	J1995	K1995	L1995	M1995
1-Jan	1/1/1995	1/2/1995	1/3/1995	1/4/1995	1/5/1995	1/6/1995	1/7/1995	12/31/1995	12/30/1995	12/29/1995	12/28/1995	12/27/1995	12/26/1995
2-Jan	1/2/1995	1/3/1995	1/4/1995	1/5/1995	1/6/1995	1/7/1995	1/8/1995	1/1/1995	12/31/1995	12/30/1995	12/29/1995	12/28/1995	12/27/1995
3-Jan	1/3/1995	1/4/1995	1/5/1995	1/6/1995	1/7/1995	1/8/1995	1/9/1995	1/2/1995	1/1/1995	12/31/1995	12/30/1995	12/29/1995	12/28/1995
4-Jan	1/4/1995	1/5/1995	1/6/1995	1/7/1995	1/8/1995	1/9/1995	1/10/1995	1/3/1995	1/2/1995	1/1/1995	12/31/1995	12/30/1995	12/29/1995
5-Jan	1/5/1995	1/6/1995	1/7/1995	1/8/1995	1/9/1995	1/10/1995	1/11/1995	1/4/1995	1/3/1995	1/2/1995	1/1/1995	12/31/1995	12/30/1995
6-Jan	1/6/1995	1/7/1995	1/8/1995	1/9/1995	1/10/1995	1/11/1995	1/12/1995	1/5/1995	1/4/1995	1/3/1995	1/2/1995	1/1/1995	12/31/1995
7-Jan	1/7/1995	1/8/1995	1/9/1995	1/10/1995	1/11/1995	1/12/1995	1/13/1995	1/6/1995	1/5/1995	1/4/1995	1/3/1995	1/2/1995	1/1/1995
-	-	-	-	-	-	-	-	-	-	-	-	-	-
25-Dec	12/25/1995	12/26/1995	12/27/1995	12/28/1995	12/29/1995	12/30/1995	12/31/1995	12/24/1995	12/23/1995	12/22/1995	12/21/1995	12/20/1995	12/19/1995
26-Dec	12/26/1995	12/27/1995	12/28/1995	12/29/1995	12/30/1995	12/31/1995	1/1/1995	12/25/1995	12/24/1995	12/23/1995	12/22/1995	12/21/1995	12/20/1995
27-Dec	12/27/1995	12/28/1995	12/29/1995	12/30/1995	12/31/1995	1/1/1995	1/2/1995	12/26/1995	12/25/1995	12/24/1995	12/23/1995	12/22/1995	12/21/1995
28-Dec	12/28/1995	12/29/1995	12/30/1995	12/31/1995	1/1/1995	1/2/1995	1/3/1995	12/27/1995	12/26/1995	12/25/1995	12/24/1995	12/23/1995	12/22/1995
29-Dec	12/29/1995	12/30/1995	12/31/1995	1/1/1995	1/2/1995	1/3/1995	1/4/1995	12/28/1995	12/27/1995	12/26/1995	12/25/1995	12/24/1995	12/23/1995
30-Dec	12/30/1995	12/31/1995	1/1/1995	1/2/1995	1/3/1995	1/4/1995	1/5/1995	12/29/1995	12/28/1995	12/27/1995	12/26/1995	12/25/1995	12/24/1995
31-Dec	12/31/1995	1/1/1995	1/2/1995	1/3/1995	1/4/1995	1/5/1995	1/6/1995	12/30/1995	12/29/1995	12/28/1995	12/27/1995	12/26/1995	12/25/1995

3 LONG-TERM MODEL DRIVERS

PJM's long-term energy and demand forecast is driven by zone-level population, economic activity as captured by regional output and employment and end-use energy trends. In general, sales growth associated with new customers and business activity is offset by improvements in energy efficiency. The 2022 PJM baseline forecast (before forecast adjustments) is basically flat when end-use energy intensities are combined with population and economic projections; decline in use per customer is roughly equal to customer growth. Long-term demand is largely driven by expected electric vehicle and data center load growth.

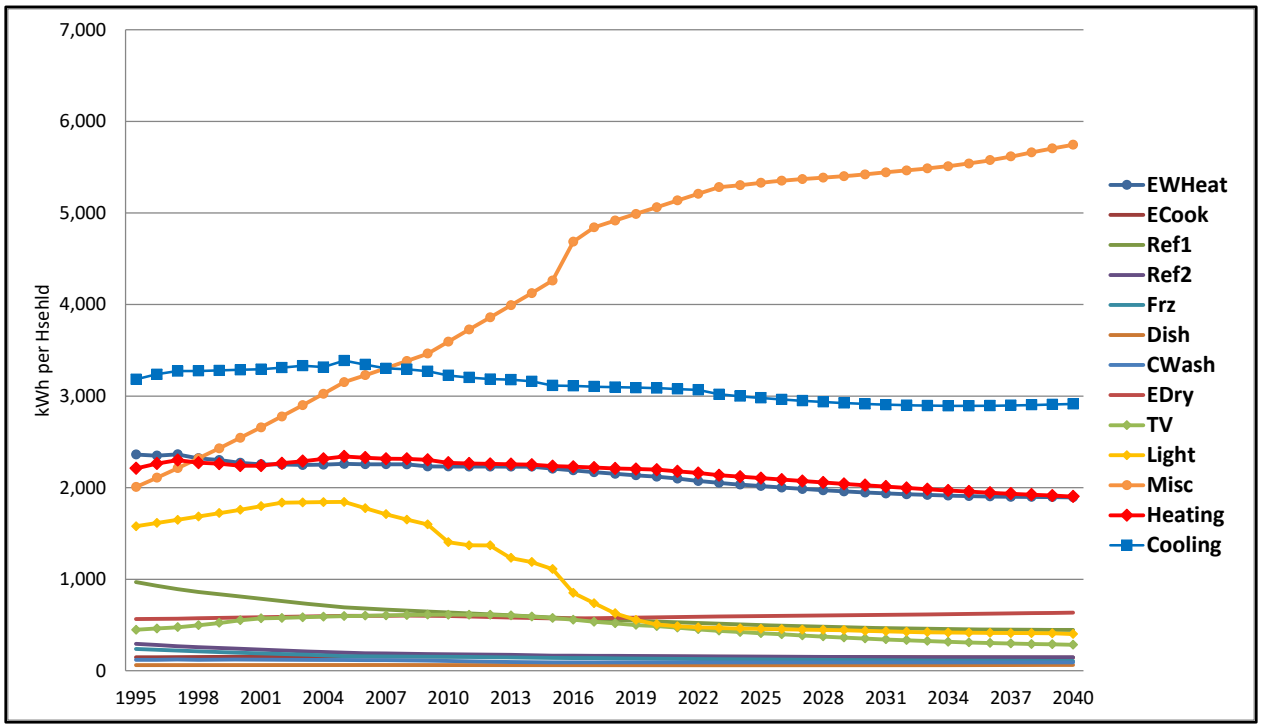
The PJM energy trend is consistent with other regions where long-term population and economic output are relatively slow. What has driven the decline in customer usage are end-use efficiency standards, utility efficiency programs that provide rebates for adoption of more efficient technology options such as lighting, and just the natural replacement of old appliances and commercial systems with new, more efficient equipment and thermal shell improvements. The current PJM model captures these energy efficiency impacts through incorporation of end-use saturation and efficiency projections. End-use saturation and average stock efficiency are derived from The Energy Information Administration (EIA) Annual Energy Outlook (AEO). The AEO forecast is based on a set of end-use models for the residential, commercial, and industrial sector. The AEO generates detail end-use information including number of households, number of end-use units, total consumption, and for many end-uses stock efficiency. Forecasts are generated for 9 census divisions as depicted in Figure 3-1.

FIGURE 3-1: FORECAST CENSUS DIVISIONS



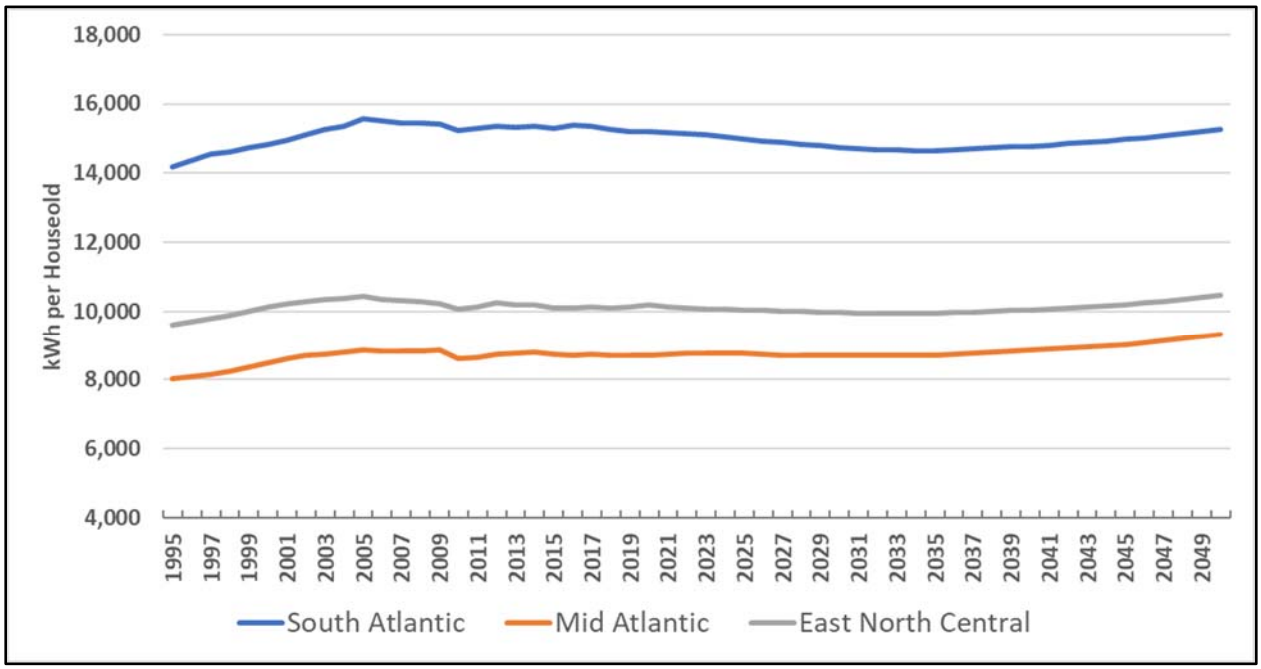
Each year, Itron processes the AEO forecast database and develops and maintains historical and projected end-use consumption, saturation, and efficiencies. Saturation and efficiency are used to construct end-use intensities. In the residential sector, intensities are on a kWh per household basis, and in the commercial sector on a kWh per square foot basis. At the national level, industrial intensities are calculated on a kWh per employee basis or kWh per $ GDP. The PJM models use intensities from the Mid-Atlantic, South Atlantic, East South Central, and East North Central Census Divisions; the specific set of intensities used in the zone model construction is determined by the zone's location. Figure 3-2 shows residential end-use intensities for the South Atlantic Census Division.

FIGURE 3-2: SOUTH ATLANTIC END-USE INTENSITIES



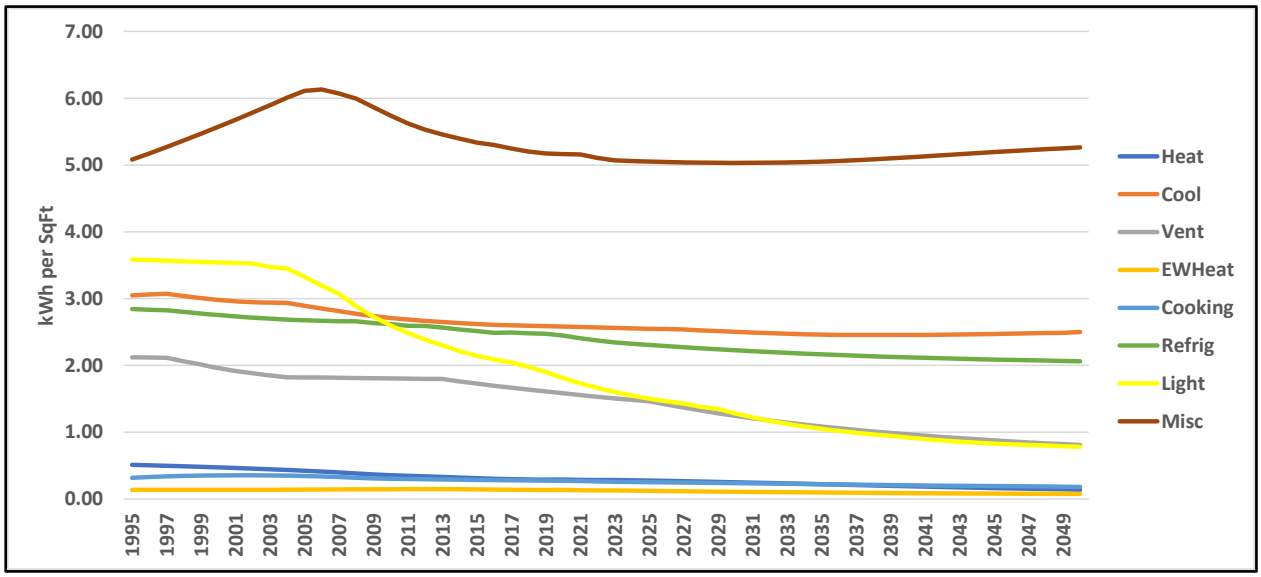
Like all Divisions, the miscellaneous category is the only end-use showing meaningful growth. Miscellaneous includes end-uses not specifically defined such as plug loads, pool pumps, spas, and wine coolers to name a few. In aggregate total intensity declines into through 2035; afterwards starts increasing as in the reference case, there are no new standards after that point in time. Figure 3-3 shows total residential intensity trend.

FIGURE 3-3: TOTAL RESIDENTIAL INTENSITIES



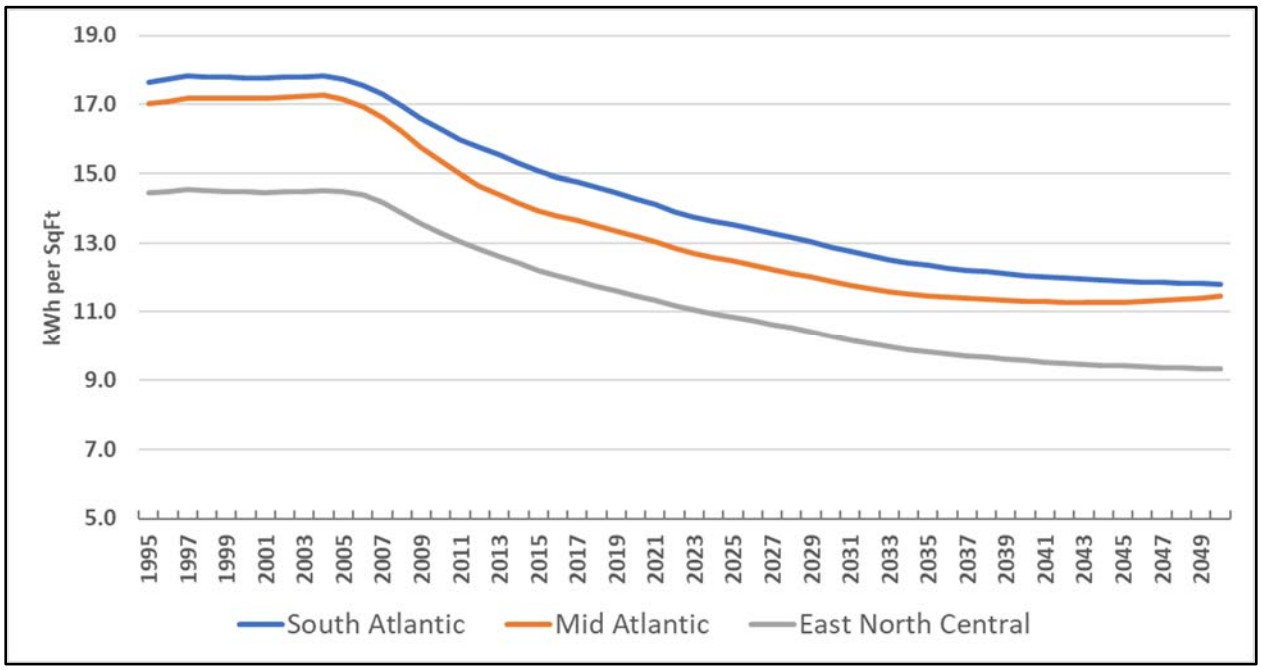
End-use intensities are also declining in the commercial sector. Figure 3-4 shows commercial end-use intensities.

FIGURE 3-4: SOUTH ATLANTIC COMMERCIAL END-USE INTENSITIES



While decline in end-use intensities are slowing across several end-uses, both lighting and ventilation are still expected to see strong overall efficiency improvements. Total commercial intensity has been declining since 2007 and is expected to continue to decline through the forecast horizon. Figure 3-5 shows total commercial intensities.

FIGURE 3-5: TOTAL COMMERCIAL INTENSITIES



TRANSITION FROM ANNUAL TO MONTHLY SECTOR MODELS

Heating Index (*HeatIdx)*, Cooling Index (*CoolIdx*), and Base Use Index (*BaseIdx*) are incorporated in the Zonal daily energy, peak, and coincident peak models. These indices are derived by combining population, economic growth, with end-use intensities allowing the indices to capture customer growth, economic activity, and current and expected gains in end-use efficiency. The construction of the indices is theoretically strong and effectively capture the impact end-use efficiency gains have had on regional sales. Resulting forecasts are consistent with EIA's long-term outlook.

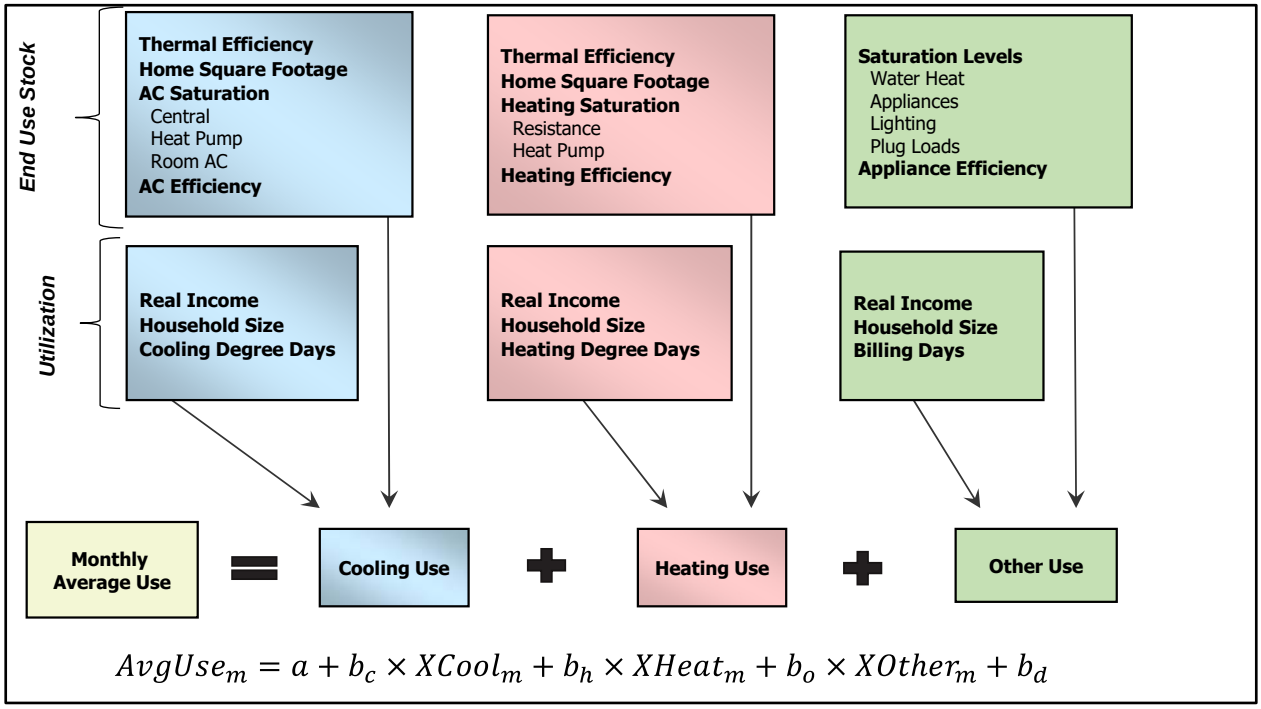
In the current PJM models, quarterly end-use indices are derived from annual customer class sales models (residential, commercial, and industrial). Annual models are estimated for each zone and reflect regional population and economic growth. While we believe the current approach adequately captures efficiency improvements, estimated indices can be strengthened and calculations simplified by deriving the indices from monthly rate class sales models rather than through annual models and calculation of quarterly indices. Monthly zone-level sales and customer can be derived from the *EIA 861 and 861m* reports. EIA 861 provides annual utility sales that includes both utility and retail served energy and customers. EIA 861m provides utility-supplied energy (which excludes retail delivered sales) that is used to shape total

annual sales to months. Monthly model provides more observations and greater variation in historical monthly use due to both weather and economic activity. This in turn results in stronger model coefficients both in terms of their impact (elasticity) and statistical strength. The use of monthly model also addresses Market Participants' concern as fewer years are required to estimate strong model coefficients used in constructing the model indices. Market Participants' issue was that using older annual data (which is necessary to have enough data points for modeling) may give too much weight to past years that are not reflective of current end-use characteristics. PJM sought to address this concern by shortening the estimation period to ten years but found they could not estimate reasonable models with just ten observations. Moving to monthly models addresses this issue; ten years of historical data gives 120 observations vs. 10 observations in an annual model. The shorter historical period will result in indices that are more reflective of current period end-use mix and economic activity impacts.

ESTIMATE RATE CLASS MODELS

The proposed approach is to construct end-use indices from monthly Statistically Adjusted End-Use (SAE) models for the residential and commercial sectors and more generalized model specification for the industrial sector. In the residential sector, the model is estimated for monthly average use and in the commercial sector for monthly sales. The SAE model is designed to capture economic growth as well as structural changes reflected in end-use saturation and efficiency trends and building shell improvements. Figure 3-6 shows the residential SAE average use model.

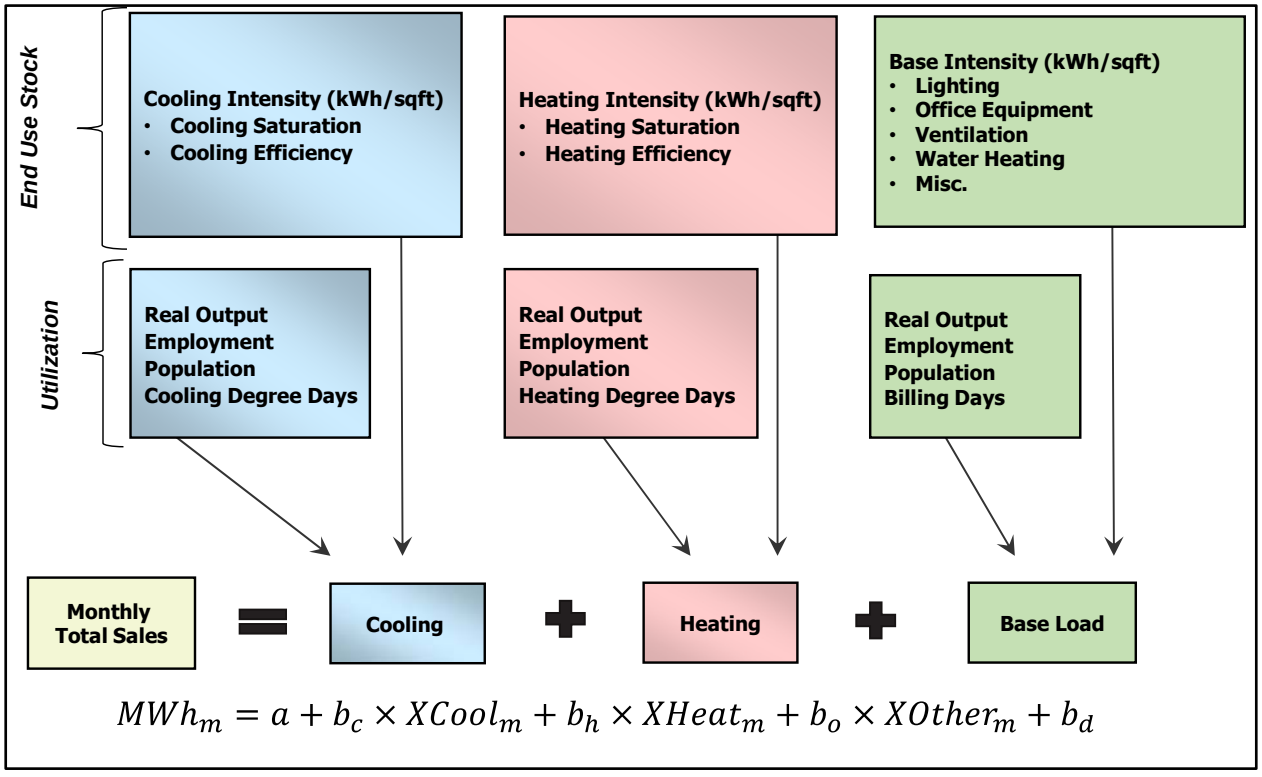
FIGURE 3-6: RESIDENTIAL SAE AVERAGE USE MODEL



The model variables *XCool*, *XHeat*, and *XOther* are initial estimates of average monthly cooling, heating, and non-weather sensitive use. The model variables are constructed by combining long-term annual saturation and efficiency trends (the end-use stock variables) with monthly weather, household income, and household size (the monthly utilization variables). The coefficients – b_c , b_h, and b_o are estimated using linear regression that relates average residential use to the constructed end-use model variable. The estimated model coefficients statistically adjust the end- use energy estimates to customer use and are used as describe below to estimate historical and projected heating, cooling, and base use loads. As parameters are estimated using an average use model, total residential heating, cooling, and baseloads are derived by multiplying per customer end-use sales by number of residential customers. Residential customer projections are based on a monthly linear regression model that relates customers to number of households.

A similar model can be estimated for the commercial sector where cooling, heating, and base-use variables are derived by combining commercial end-use energy intensity (measured in kWh per square foot) with regional economic drivers that capture both economic growth and short-term business activity. Figure 3-7 shows the commercial SAE model.

FIGURE 3-7: COMMERCIAL SAE SALES



In general, commercial models are estimated at total sales level. The estimated model coefficients calibrate commercial end-use energy estimates to actual commercial sales.

The monthly SAE specification was evaluated and presented to PJM staff using DPL Zone rate class monthly sales data, economic data, and EIA Census Division residential and commercial end-use intensities. Recent data developed by the National Renewable Energy Laboratory (NREL) can potentially be used to help calibrate the census-level saturation estimates to Zones. NREL has constructed detail residential (ResStock) and commercial (ComStock) end-use data bases derived from thousands of residential and commercial building simulations. 2018 end-use saturation and consumption can be calculated for each Public Use Microdata Area (PUMA). PUMA disaggregate states into regions with no fewer than 100,000 people. Figure 3-8 shows residential actual and predicted average use and Figure 3-9 shows DPL commercial sales model.

FIGURE 3-8: DPL RESIDENTIAL SAE MODEL

Variable	Coefficient	StdErr	T-Stat	P-Value
mStructResVar.XHeat	0.611	0.041	14.962	0.00%
mStructResVar.lag_XHeat	0.385	0.040	9.596	0.00%
mStructResVar.XCool	0.579	0.029	20.275	0.00%
mStructResVar.lag_XCool	0.271	0.028	9.580	0.00%
mStructResVar.XOther	0.694	0.016	42.501	0.00%

Model Statistics	
Iterations	1
Adjusted Observations	132
Deg. of Freedom for Error	127
R-Squared	0.899
Adjusted R-Squared	0.896
AIC	8.507
BIC	8.616
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-743.74
Model Sum of Squares	5,411,707.85
Sum of Squared Errors	605,458.10
Mean Squared Error	4,767.39
Std. Error of Regression	69.05
Mean Abs. Dev. (MAD)	50.32
Mean Abs. % Err. (MAPE)	5.02%
Durbin-Watson Statistic	1.739
Durbin-H Statistic	#NA
Ljung-Box Statistic	21.44
Prob (Ljung-Box)	0.6124

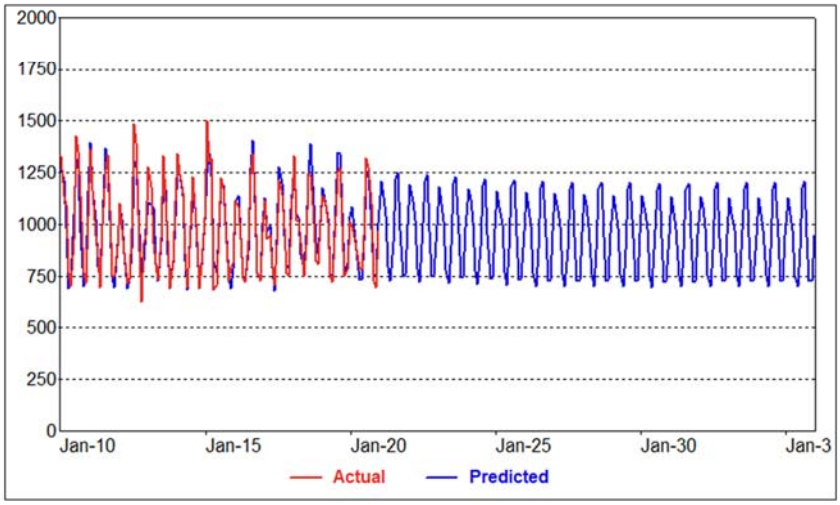
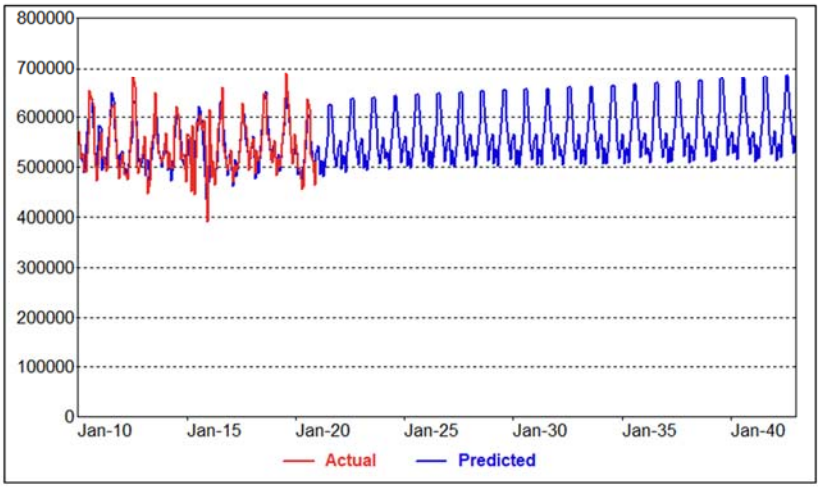


FIGURE 3-9: DPL COMMERCIAL SAE MODEL

Variable	Coefficient	StdErr	T-Stat	P-Value
mStructComVar.XHeat	603682.895	79802.942	7.565	0.00%
mStructComVar.XCool	169975.308	16510.469	10.295	0.00%
mStructComVar.lag_XCool	44790.922	15989.044	2.801	0.59%
mStructComVar.XOther	37659.345	441.829	85.235	0.00%
mBin.Yr2018Plus	11113.086	5608.705	1.981	4.97%
mBin.Dec2015	-107557.755	29095.540	-3.697	0.03%

Model Statistics	
Iterations	1
Adjusted Observations	132
Deg. of Freedom for Error	126
R-Squared	0.747
Adjusted R-Squared	0.737
AIC	20.58
BIC	20.71
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-1,539.42
Model Sum of Squares	308,160,817,274.05
Sum of Squared Errors	104,181,634,515.42
Mean Squared Error	826,838,369.17
Std. Error of Regression	28,754.80
Mean Abs. Dev. (MAD)	19,750.20
Mean Abs. % Err. (MAPE)	3.67%
Durbin-Watson Statistic	2.350
Durbin-H Statistic	#NA
Ljung-Box Statistic	30.64
Prob (Ljung-Box)	0.1643
Skewness	0.077
Kurtosis	5.269
Jarque-Bera	28.440
Prob (Jarque-Bera)	0.0000



The models generate statistically significant end-use coefficients that can be used to generate strong estimates of cooling, heating, and base-use energy requirements. Another strength is that given the structure, the SAE model generally results in consistent estimated parameters when there are just small changes in model parameters as new data is added and older data dropped.

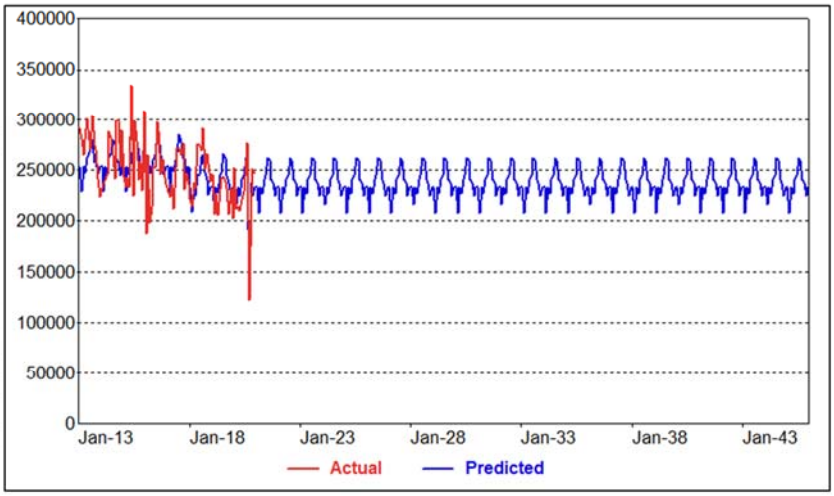
Similar structured models can be estimated for the industrial sector. To that end, PJM constructed industrial models that leverage the EIA industrial sector energy forecasts. In the industrial sector, EIA generates energy per dollar output projections by industrial sector. Using a combination of state-level output estimates and regional sector employment data, PJM constructs annual industrial indices that reflect Zonal industrial sector real output, productivity, and efficiency improvements. Itron has developed similar inputs for industrial modeling and believe that the PJM current industrial model process is theoretically strong. While structured models have worked in some regions, often they don't as in many service areas monthly industrial sales are not "well-behaved"; in these cases, PJM will need to use reasonable judgment in constructing monthly sales models and may require exogenous adjustments based on expected activity from large industrial customers. Industrial sales are often dominated by a few large customers; there can be significant month-to-month sales variation as a result of large swings in individual customer usage and large billing adjustments.

This is illustrated in Figure 3-10 where we could not estimate a reasonable DPL industrial sales model. Not only are there large monthly sales swings that are not weather-related, but there is a drop in 2018 sales that could be the result of one or more large customer closing down part or all of their operations.

FIGURE 3-10: DPL INDUSTRIAL SALES MODEL

Variable	Coefficient	StdErr	T-Stat	P-Value
mWthrCal.Days	8182.112	123.024	66.508	0.00%
mWthrCal.CDD60	65.106	14.350	4.537	0.00%
mBin.Yr2018Plus	-20698.365	5168.287	-4.005	0.01%
mBin.Sept20	-119005.506	24678.138	-4.822	0.00%

Model Statistics	
Iterations	1
Adjusted Observations	96
Deg. of Freedom for Error	92
R-Squared	0.431
Adjusted R-Squared	0.413
AIC	20.24
BIC	20.34
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-1,103.56
Model Sum of Squares	41,138,783,394.60
Sum of Squared Errors	54,275,336,134.38
Mean Squared Error	589,949,305.81
Std. Error of Regression	24,288.87
Mean Abs. Dev. (MAD)	18,817.72
Mean Abs. % Err. (MAPE)	7.55%
Durbin-Watson Statistic	1.913
Durbin-H Statistic	#NA
Ljung-Box Statistic	35.85
Prob (Ljung-Box)	0.0567
Skewness	0.182
Kurtosis	3.263
Jarque-Bera	0.807
Prob (Jarque-Bera)	0.6679



Without any strong identifiable model drivers, the forecast is held constant at current levels of activity. Generally, the industrial sales forecast would then be adjusted for expected large customer load additions or load losses. While limited in terms of information, model coefficients can be still be used to isolate industrial cooling and base-use contribution to system energy requirements.

SYSTEM END-USE MODEL INPUT CONSTRUCTION

The next step is to isolate long-term system heating, cooling, and other-use energy requirements for both the historical and forecasted periods. End-use energy requirements are estimated by multiplying the end-use model coefficients with the constructed XHeat and XCool for normal weather and the XOther model variables. Normal or expected weather conditions are used in the XHeat and XCool index calculations to avoid double counting weather impacts. Weather impacts are captured in the daily or hourly zonal load weather simulations. Figure 3-11 shows the derived residential heating, cooling, and base-use loads,

Figure 3-12 the commercial and industrial monthly energy requirements, and Figure 3-13 total system cooling, heating, and baseload requirements.

FIGURE 3-11: DPL RESIDENTIAL END-USE ENERGY REQUIREMENTS (MWH)

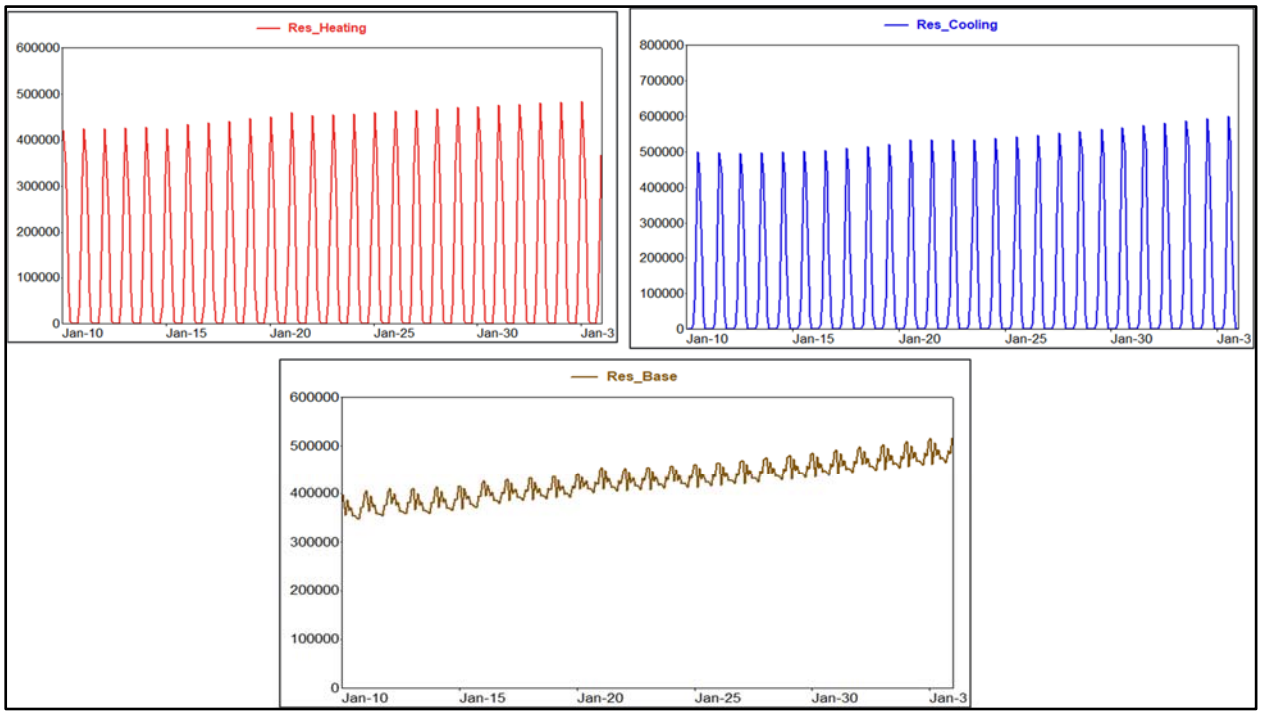


FIGURE 3-12: DPL C&I END-USE ENERGY REQUIREMENTS (MWH)

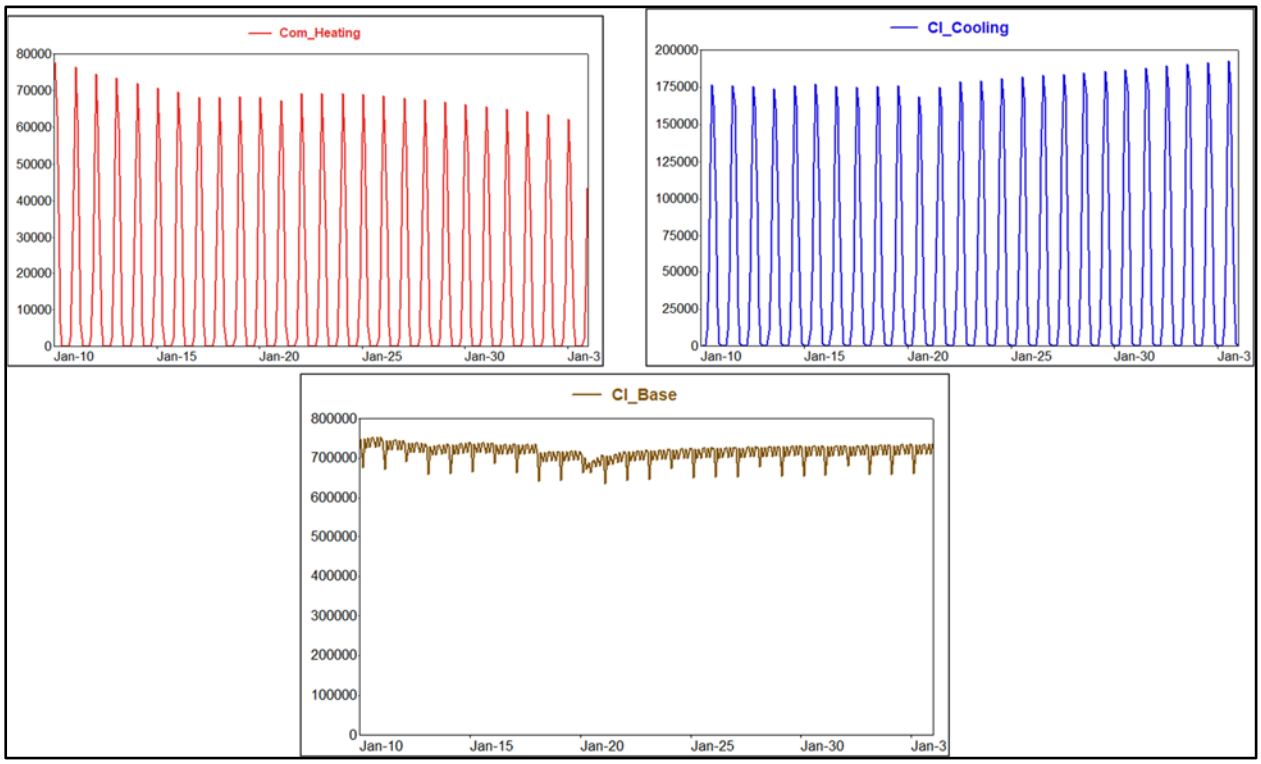
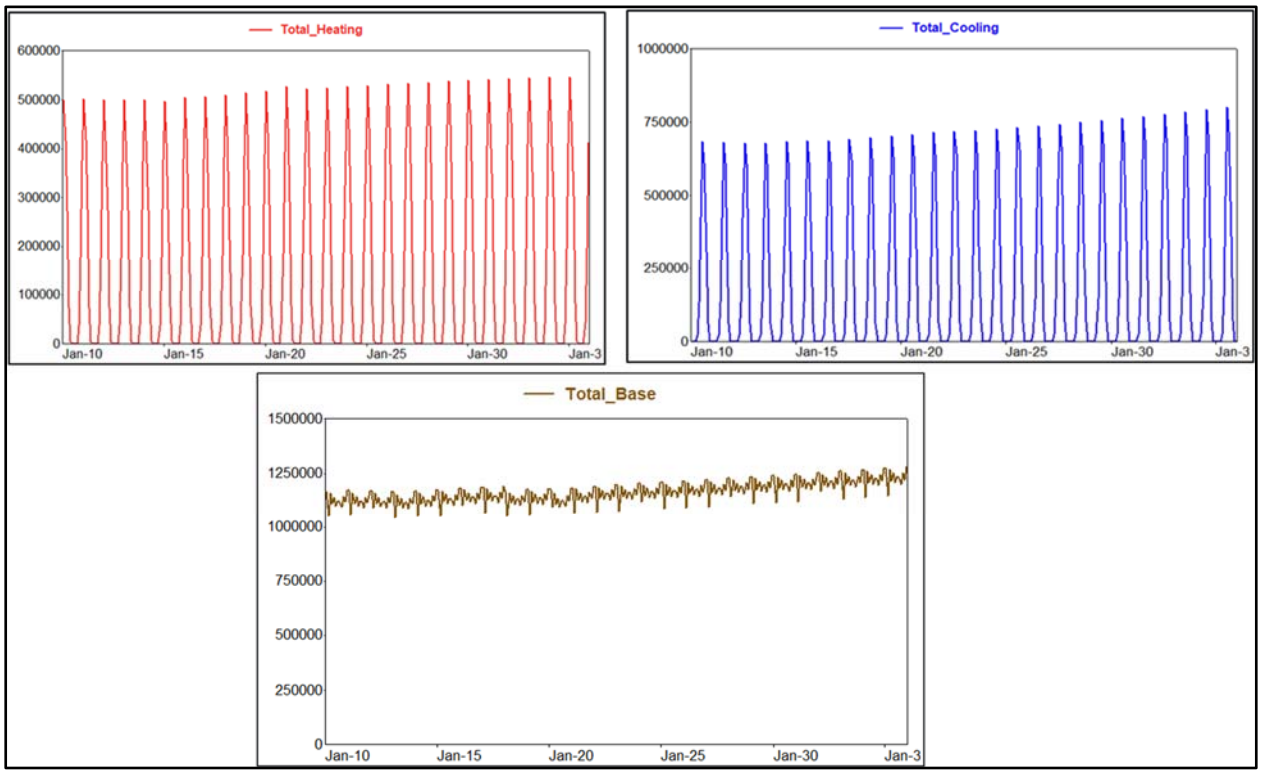
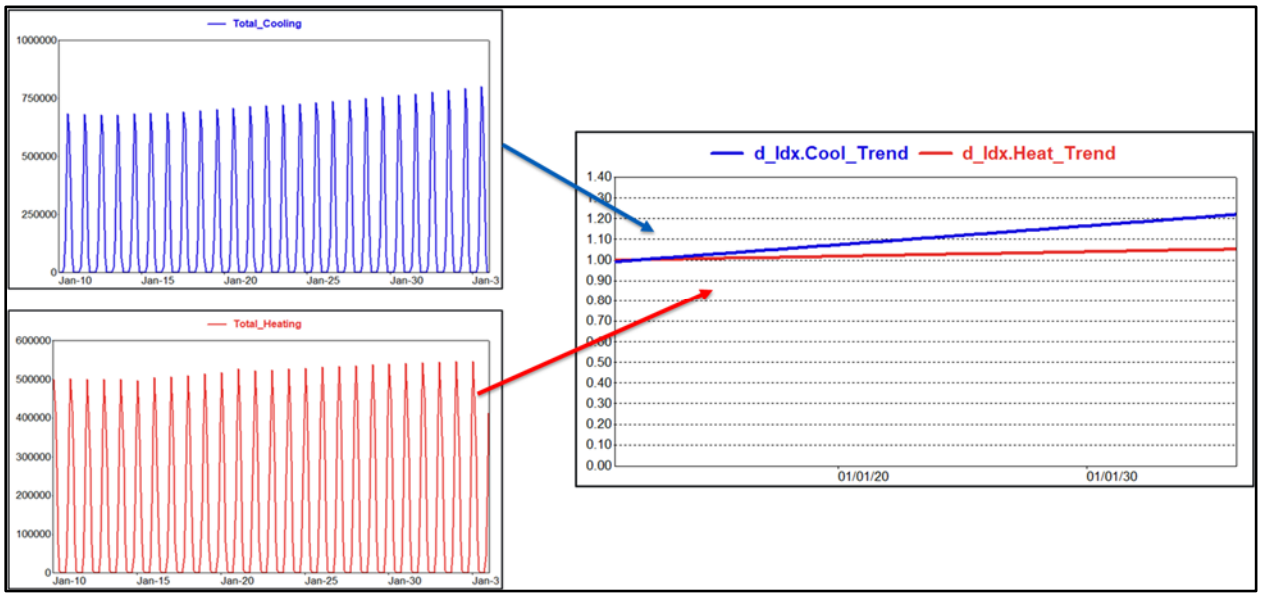


FIGURE 3-13: DPL TOTAL END-USE ENERGY REQUIREMENTS (MWH)



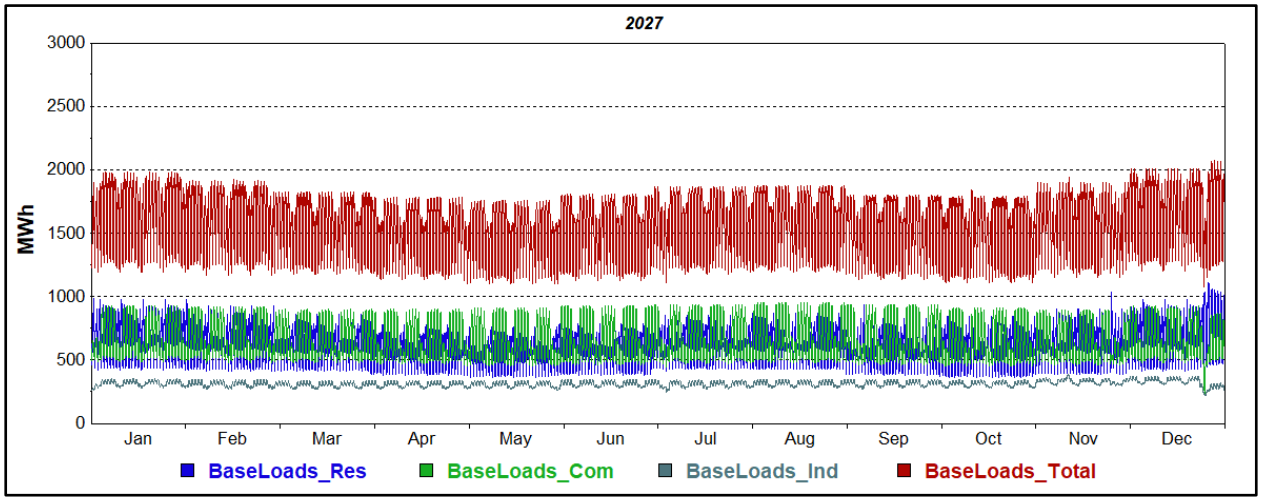
Calculated heating, cooling, and base-use energy requirements are converted to daily indices that are then incorporated into the Zonal hourly load models. *HeatIdx* is combined with the hourly model heating-related weather variables, *CoolIdx* with cooling weather variables, and *BaseIdx* with seasonal and daily binary variables. Figure 3-14 shows the conversion of monthly end-use energy requirements to *HeatIdx* and *CoolIdx*.

FIGURE 3-14: DPL DAILY INPUTS FOR HOURLY ZONAL MODELS



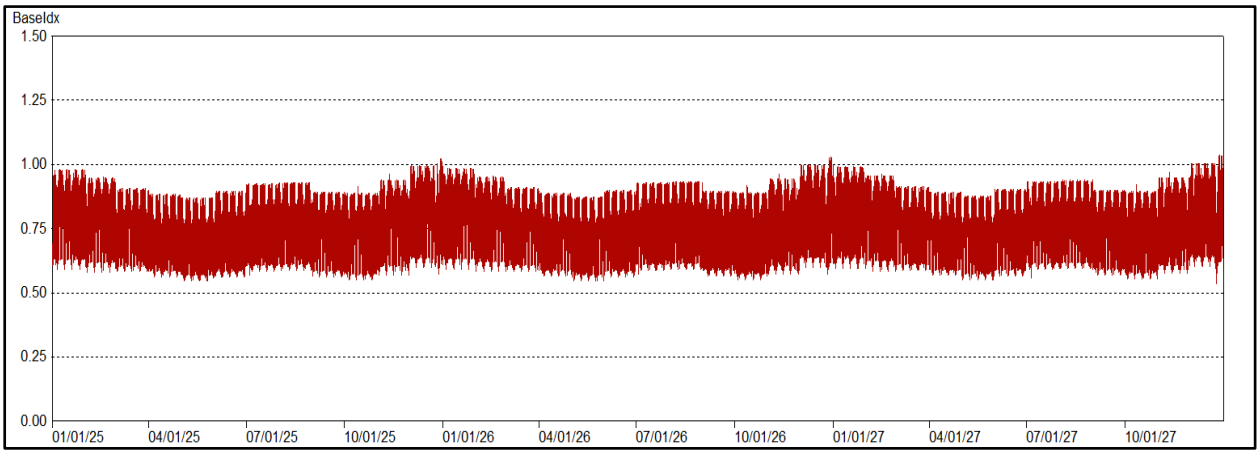
Base-use energy requirements are also converted to a daily index and interacted with hourly model binaries designed to capture non-weather sensitive load including day of the week, holiday, and seasonal daily variables. Alternatively, AMI data or end-use profiles available from NREL could be used to convert customer class base-use energy requirements to hourly load estimates. Figure 3-15 shows estimated DPL hourly base-use energy requirements by class and total for 2027.

FIGURE 3-15: DPL HOURLY BASE-USE ENERGY REQUIREMENTS (2027)



Total base-use load requirements are indexed and used in estimating the hourly Zonal models. Figure 3-16 shows the hourly BaseIdx variable for 2025 through 2027.

FIGURE 3-16: DPL BASEIDX 2025 - 2027



The integration of the end-use indices into the hourly models is discussed in the Hourly Model Analysis and Recommendations section.

4 HOURLY MODEL ANALYSIS AND RECOMMENDATIONS

The current PJM modeling process includes three sets of daily models for each zone. These are daily energy, daily noncoincident zone peak (NCP), and daily CP (zone load at the time of the daily PJM peak). For each zone, CP models are estimated for daily loads coincident with the Locational Deliverability Area (LDA) peak and coincident with the overall PJM system peak.

The application of this approach is complicated by the saturation of new technologies (PV and EV in particular) that modify the timing of system energy requirements. In particular, the penetration of behind the meter solar systems is changing both the timing of zone peaks and the coincidence factors across zones. The best way to understand the impact of these changes is through an hourly modeling process. This section shows how the hourly modeling process would work, provides an example of the level of accuracy that can be achieved, and provides recommendations about the construction of hourly weather variables.

The examples are developed using hourly load and weather data for the DPL (Delmarva) zone. As part of this project, Itron did not evaluate model performance for any other PJM zones. However, in the past we have implemented similar models and performed similar analysis for a wide variety of utilities, including many of those in the PJM footprint. Based on this experience, we believe that the conclusions presented below will generalize well to the other PJM zones.

The general conclusions of this section are:

- PJM has the data to develop accurate and robust hourly models
- Hourly models are well suited to the weather simulation approach
- Hourly models can accurately model system zone peaks (NCP) and the coincident load (CP) values.
- The conclusions include specific recommendations for construction of interactive weather variables.

EXAMPLE OF HOURLY LOAD DATA

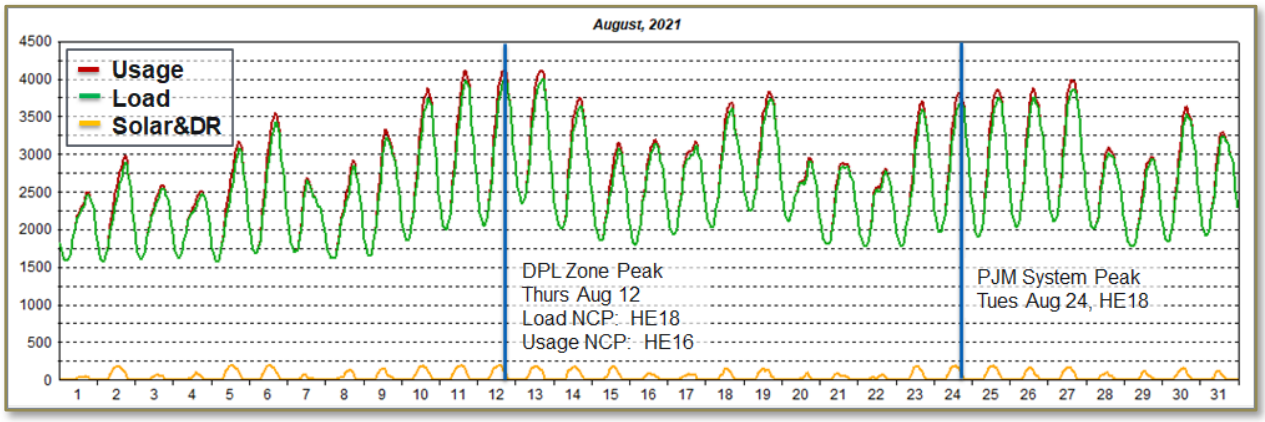
Figure 4-1 shows an example of hourly load data for the DPL (Delmarva) zone. The chart shows hourly data for one month, August 2021. The top line (Red) is labeled Usage and shows the estimate of hourly energy usage (customer end-use consumption). The Green line is labeled Load and shows the level of zone resources dispatched to meet customer energy requirements. The bottom line (Orange) shows the estimated level of behind-the-meter solar generation.

The utility load is computed as the measured hourly zone load plus estimated hourly impacts of DR programs. (Note, there were no estimated DR impacts in the DPL zone in the month displayed). The orange line (Solar) is estimated and is based on hourly solar irradiation data and installed capacity of behind-the-meter solar panels. The red Usage line is calculated as the sum of utility load (Green) and

solar Generation (Orange). This is an estimate of total customer energy usage, including energy supplied by BTM solar systems and energy supplied by the zone resources.

In the chart, the two vertical blue lines represent the day and time of the DPL zone peak (on August 12) and the PJM system peak (on August 24). On the zone peak (NCP) day, customer usage peaked at HE17 (4 pm to 5 pm), but the peak utility peak load occurred in the following hour (HE18) as BTM solar production ramped downward. It was a clear day, so this is just part of the normal ramp-down process for solar generation and the resulting ramp-up process for utility loads in the late afternoon. As a point of reference, peak solar generation on this day was estimated to be 197 MW.

FIGURE 4-1: DPL HOURLY USAGE, LOAD, AND BTM SOLAR – AUGUST 2021



DPL Data	Usage Peak 8/12/HE17	NCP 8/12 HE18	CP 8/24 HE18	Coincidence Factor
Usage	4,106.9	4,100.3	3,753.6	91.4%
Solar_DR	132.9	94.3	83.6	
DPL Load	3,974.0	4,006.0	3,670.0	91.6%

The right-hand blue line on August 24th represents the PJM System peak load. Although not shown in the grid above, customer usage on this day peaked in HE16, load peaked in HE17, and the PJM peak is at HE18. Customer usage is estimated to have declined by about 73 MW over this three-hour window, but solar generation values ramped down by about the same amount (from 156 MWh to 125 MWh to 84 MWh, respectively), and as a result, net DPL load was relatively flat from the time of the customer peak to the time of the PJM peak.

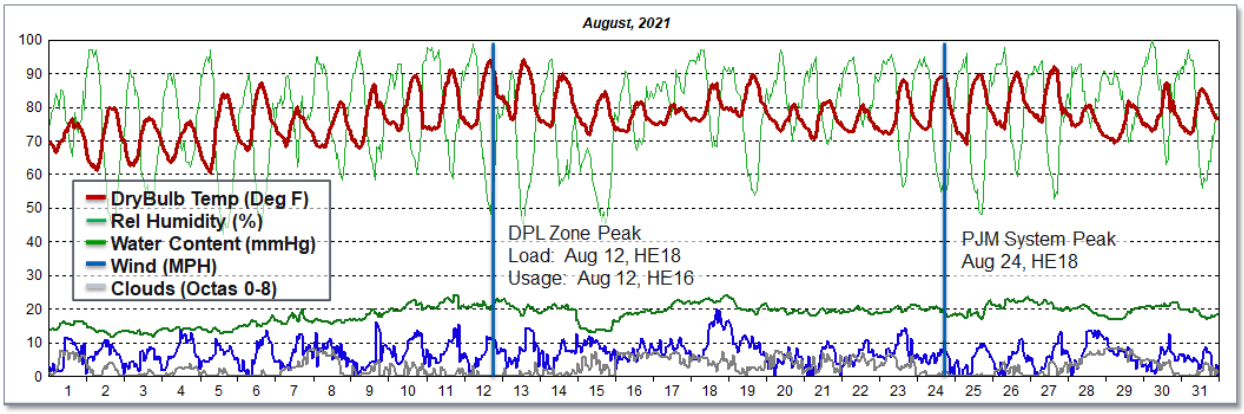
The grid below the chart pulls together the data for the hour of usage peak, the hour of DPL peak load (NCP) and the DPL load at the time of the PJM system peak (CP). The coincidence factor for usage (CP usage/Peak usage) is estimated to be 91.4%. The coincidence factor for DPL load (CP load /NCP load) is 91.6%. This is well below the typical coincidence values for the DPL area but is within the boundaries of coincidence results generated by the weather simulation approach with rotation.

EXAMPLE OF HOURLY WEATHER DATA

Figure 4-2 shows an example of weather for the DPL (Delmarva) zone. The chart shows hourly values for the same month as shown above, August of 2021. The weather data values are computed by averaging hourly data from the two weather stations, Wilmington, Newcastle (ILG) in the north and Wallops Island (WAL) in the south; based on associated population, ILG has a 70% weight and WAL a 30% weight. The red line shows data for hourly drybulb temperature. The light green line shows data for relative humidity. The dark green line shows hourly data for the moisture content of the air in millimeters of mercury (mmHg). The blue and gray lines at the bottom are for Wind speed in MPH and Cloud Cover in Octas (ranging from 0 to 8).

As with the hourly load chart, the hours for the DPL zone peak and the PJM system peak are marked with vertical blue lines. The hourly weather data for these two peak hours is displayed below the chart.

FIGURE 4-2: HOURLY WEATHER DATA FOR DPL ZONE – AUGUST 2021



Summer Peak Hour Weather Variables	DPL 2021 NCP 8/12 HE18	PJM 2021 Peak 8/24 HE18
AvgDB Temperature (Deg F)	92.7	88.8
Relative Humidity (%)	54.3	53.3
Moisture Content (mmHg)	21.3	19.1
Temp Hum Index (Deg F)	95.4	91.1
Wind Speed (MPH)	11.4	8.4
Cloud Cover (Octas)	0.12	1.6

The peak hour data show the main difference between the two days, which is that the DPL zone is four degrees warmer on the NCP day than on the peak day. The THI variable that is used in the model is 4.3 degrees higher. Estimated equations indicate that 4 additional degrees of temperature in HE18 and the preceding hours adds about 290 MWh to the load in HE18. This explains why the DPL peak on August 12 is so far above the DPL CP value on August 24.

While we are on the topic of weather, a brief comment about the THI variable and relative humidity. The normal daily cycles are clear in the weather chart. Each day, the temperature increases to a mid-day high and then decreases at night to lower values. As this cycle occurs, the amount of water that the air can hold changes significantly, since warmer air can hold much more water than colder air. Relative humidity represents ratio of the amount of moisture in the air to the amount of moisture the air can hold. The amount of moisture in the air (the numerator) remains relatively constant over most days, but as the temperature drops at night the amount of water the air can hold (the denominator) goes down, and therefore relative humidity goes up. This continues until the air temperature hits the dew point temperature, at which point relative humidity approaches 100%.

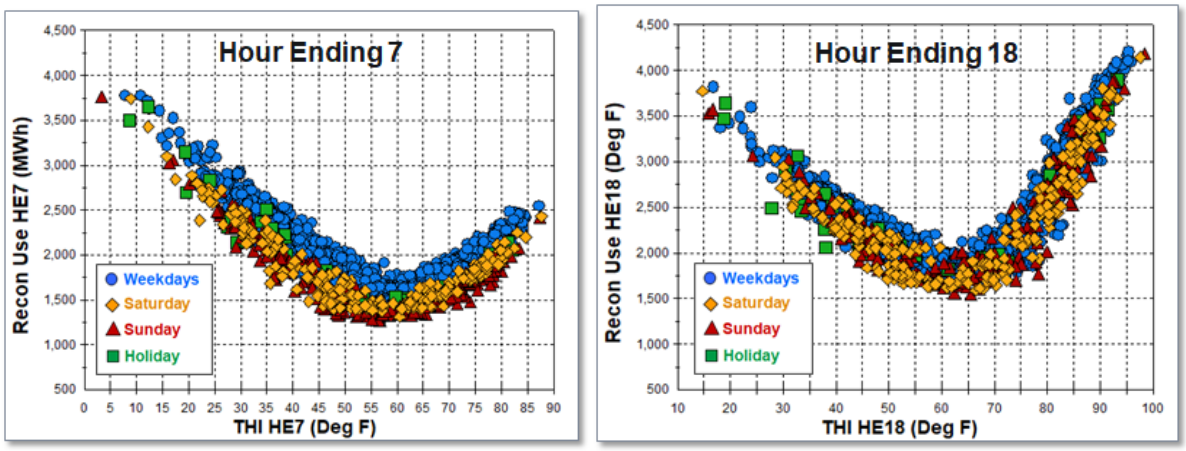
The dark green line shows a measurement that is proportional to the numerator in the relative humidity equation. It measures the absolute amount of moisture in the air in each hour. Unlike relative humidity, this water content measurement does not change much during a day. In the work below, we discuss the THI formula based on Relative Humidity. It may, however, make sense to research alternatives that utilize a more stable measurement like moisture content or dewpoint temperature.

HOURLY MODELS

This section provides an analysis of alternative approaches to constructing hourly models. Itron has studied a wide range of modeling methods including a variety of regression approaches (least squares, ridge, lasso, elastic net, quantile, support vector), decision tree regressors, and neural network models. While neural network models typically have the best estimation period accuracy, they are more complex than regressions, and can be problematic when explanatory variables move far outside their historical range, as is likely the case in a long-term forecast. We have found that least squares regression (usually called ordinary least squares or OLS) works as well as any of the alternatives in terms of out-of-sample accuracy and provide a robust approach for long-run forecasting of daily and hourly energy usage. Based on these past findings, we restrict our attention here to OLS methods.

The typical approach for long-run forecasting is to specify 24 independent structural models, with one model for each hour. The idea is illustrated in Figure 4-3 that shows scatter plots of loads at HE07 (the hour from 6 am to 7 am) and HE18 (the hour from 5 pm to 6 pm). In these charts, the height of each point represents the estimated hourly usage for the selected hour on a specific day. The position on the X axis is determined by the corresponding hourly temperature (THI in this case) on each day. The points are color coded by day of the week. Each chart shows data for mid-2017 to mid-2021, providing about 1,500 observations for each hour.

FIGURE 4-3: SCATTER PLOTS FOR HE07 AND HE18 – 2017 TO 2021



While temperature and day-of-week variables clearly explain much of the variation in loads in an hour, a variety of other factors are also important. This includes zone growth in terms of customers and economic activity, other weather variables (prior hour temperatures, humidity, wind speed, and cloud cover), seasonal factors (hours of daylight, sun angles, ground water temperatures), changes in end-use saturation and efficiency, and exogenous shocks, such as phases of the Covid pandemic.

Proper construction of explanatory variables that capture the important nonlinearities and interactions among these factors is the key to a strong and robust explanatory model. In what follows, most of the focus is on weather variable definitions and interactions since this will be central to the effectiveness of the weather simulation approach.

TRANSFORMING HOURLY WEATHER

The first analysis concerns the granularity of weather variables that are used in the hourly modeling. Data used in the analysis ranged from mid-2017 through early 2022, giving a total slightly over 1,700 observations for each hour. The hourly Y variable in this analysis is utility load (in later sections, the final model evaluations were performed using hourly usage).

Four sets of models were constructed and compared in terms of in-sample accuracy. All four sets have a common set of calendar-based variables, including the following:

- Monthly binary variables
- Monthly trend variables to capture within-month trends
- Holiday variables for individual holidays
- Long weather lags (10 day and 28-day CD and HD)
- Covid variables Phase 1 to Phase 4 to capture net covid impacts
- Time trend variable

The four sets of models differ in the way hourly weather is transformed into explanatory factors. The approaches are:

1. **Daily Average**. With this approach, hourly values are averaged for each day and the daily average variables are used to construct explanatory factors.
2. **Time-of-Day Average**. With this approach, hourly values are averaged within four time of day blocks (night, morning, afternoon, evening). The TOD averages are then used to construct explanatory factors.
3. **Rolling Hourly with Splines.** With this approach weather variables are computed for each hour as the centered moving average of the prior hour, current hour, and next hour values. The rolling hourly variables are used to construct heating degree and cooling degree variables using 5 degree temperature ranges. For example, THI degrees are computed using base values of 60, 65, 70, 75, 80 and 85. These variables are then used to construct a single heating degree spline and cooling degree spline based on temperature derivatives computed using hourly neural network models. The spline variables are then interacted with other calendar and weather variables to capture slope shifts and nonlinear interaction effects.
4. **Rolling Hourly with Two-Part Degree Days**. With this approach, two cooling degree variables and two heating degree variables are computed for each hour. For example, for HE18, cooling degrees are computed using base temperatures of 70 and 80 and heating degrees are computed using base temperatures of 60 and 50. The first heating degree variable (HD1) and the first cooling degree variable (TD1) are then interacted with other calendar and weather variables to capture slope shifts and nonlinear interaction effects.

To evaluate the relative power of these approaches, a full set of hourly models is estimated using each approach. The mean absolute percent error (MAPE) values from these models are used for the comparison. For each hour, this statistic is computed as the average of the absolute values of the estimated model errors for that hour.

Daily Average Models. For the Daily Average model, daily weather values are computed by averaging the hourly values across the hours in each day. Steps in the process are:

Hourly drybulb temperatures and hourly humidity values are used to compute hourly THI values.

Hourly values are then averaged for each day to get a daily average values (AvgDB, AvgTHI, AvgWind, AvgClouds).

- Two cooling degree variables are computed from AvgTHI using base temperatures of 60 and 70 (AvgTD1 and AvgTD2).
- Two heating degree variables are computed from AvgDB using base temperatures of 60 and 50 (AvgHD1 and AvgHD2)
- AvgTD1 and AvgHD1 are lagged one day and are also interacted with calendar and other weather variables:
    - TD1 and HD1 lagged one day
    - Cold Clouds (Clouds interacted with HD base 50)

- Warm Clouds (Clouds interacted with CD base 70)
- Cold Wind (Wind interacted with HD base 50)
- Warm Wind (Wind interacted with CD base 70)
- SpringTHI and FallTHI (Seasonal binaries interacted with TD1)
- SpringHD and Fall HD (Seasonal binaries interacted with HD1)
- WkEndTHI, WkEndHD (Weekend binary interacted with TD1 and HD1)
- TrendTD1 and TrendHD1 (Trend variable interacted with TD1 and HD1)

Time of Day (TOD) Models. For the Time-of-Day models, hourly weather values are averaged for the four quarters of the day: Night (HE01 to HE06), Morning (HE07 to HE12), Afternoon (HE13 to HE18) and Evening (HE19 to HE24).

- Hourly drybulb temperatures and hourly relative humidity values are used to compute hourly THI values.
- Hourly values are then averaged for each TOD block to get an average variable values (AvgDB), AvgTHI, AvgWind, and AvgClouds for each block.
- Two cooling degree variables are computed for each block using base temperatures that vary across blocks (60 and 70 for Night, 65 and 75 for Morning, Afternoon and Evening)
- Two heating degree variables are computed for each block using base temperatures that vary across blocks (55 and 45 for Night and Evening, 60 and 50 for Morning and Afternoon).
- Lag and interaction variables similar to those in the Daily Average model are then constructed for each TOD block.

For each hour, the TD1 and HD1 variables are included for the block the hour falls in as well as for the prior block and the following block. This surrounding block values are included to improve performance in the hours near the block boundaries.

Rolling Hourly Models. For the Rolling hourly models, weather variables are computed for each hour. Moving from one hour to the next, all calculations shift one hour to the right, including current hour variables and lagged hour variables. Steps in the process are:

For each weather variable (temperature, humidity, clouds, and wind), the hourly value is computed as a centered moving average of the values for the prior hour, the current hour, and the next hour. In test estimations, this three-hour average (MAPE = 2.29%) worked a bit better than a two-hour average (MAPE = 2.32%), which worked a bit better than the current hour reading alone (MAPE = 2.36%).

Starting with the 3-hour average for each hour, drybulb temperatures and relative humidity values are used to compute THI values for each hour.

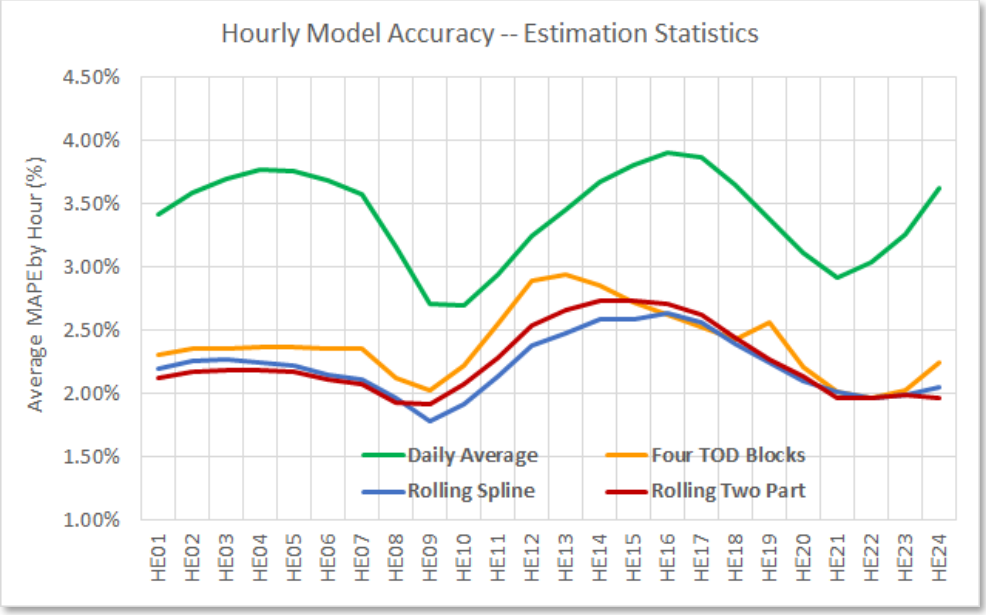
Rolling Spline Models. Starting with the 3-hour average drybulb values for heating and THI values for cooling, a full set of HD and TD variables are computed with 5 degree buckets. Base temperatures for HD are 65, 60, 55, 50, 45, 40, and 30. Base temperatures for TD are 55, 60, 65, 70, 75, 80, 85, 90.

HD and TD values in successive buckets are combined into a single HDSpline variable and a single TDSpline variable.

Rolling Two-Part Models. Starting with the 3-hour average drybulb values for heating and THI values for cooling, HD values are computed for each hour with two base temperatures (HD1 and HD2) and TD values are computed for each hour with two base temperatures (TD1 and TD2). The base temperature values are all at 5-degree points, and vary by hour, as shown in Figure 4-4.

Lag and interaction variables similar to those in the Daily Average model are then constructed for each hour of the day, using the 3-hour average weather variables.

FIGURE 4-4: ESTIMATION HOURLY MAPE STATISTICS – COMPARISON OF METHODS



Hour	DailyAvg Wthr	Four TOD Blocks	Rolling Spline	Rolling Two Part
HR00	3.42%	2.31%	2.20%	2.12%
HR01	3.59%	2.36%	2.26%	2.17%
HR02	3.69%	2.36%	2.27%	2.19%
HR03	3.77%	2.37%	2.24%	2.18%
HR04	3.76%	2.37%	2.22%	2.17%
HR05	3.68%	2.35%	2.15%	2.11%
HR06	3.57%	2.35%	2.11%	2.08%
HR07	3.16%	2.12%	1.96%	1.93%
HR08	2.71%	2.03%	1.78%	1.91%
HR09	2.69%	2.22%	1.92%	2.08%
HR10	2.94%	2.55%	2.14%	2.28%
HR11	3.24%	2.89%	2.38%	2.54%
HR12	3.45%	2.94%	2.48%	2.66%
HR13	3.67%	2.86%	2.59%	2.73%
HR14	3.81%	2.72%	2.59%	2.73%
HR15	3.90%	2.62%	2.64%	2.71%
HR16	3.86%	2.53%	2.56%	2.62%
HR17	3.65%	2.43%	2.39%	2.44%
HR18	3.38%	2.56%	2.25%	2.27%
HR19	3.11%	2.21%	2.10%	2.14%
HR20	2.92%	2.01%	2.01%	1.96%
HR21	3.04%	1.96%	1.97%	1.96%
HR22	3.26%	2.02%	1.99%	1.99%
HR23	3.62%	2.24%	2.05%	1.97%
Avg	3.41%	2.39%	2.22%	2.25%
#Coef	78	75	79-81	82

Two-part TD & HD base temperatures

Hour	TD1	TD2	HD1	HD2
HE01	65	75	55	45
HE02	65	75	55	45
HE03	65	75	55	45
HE04	65	75	55	45
HE05	65	75	55	45
HE06	65	75	55	45
HE07	65	75	55	45
HE08	65	75	55	45
HE09	65	75	55	45
HE10	65	75	55	45
HE11	70	80	60	50
HE12	70	80	60	50
HE13	70	80	60	50
HE14	70	80	60	50
HE15	70	80	60	50
HE16	70	80	60	50
HE17	70	80	60	50
HE18	70	80	60	50
HE19	70	80	60	50
HE20	65	75	55	45
HE21	65	75	55	45
HE22	65	75	55	45
HE23	65	75	55	45
HE24	65	75	55	45

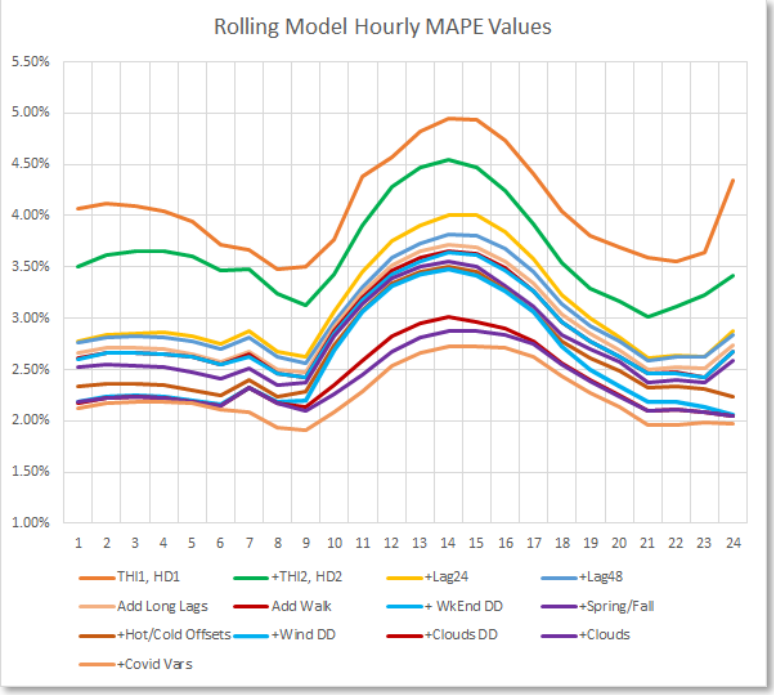
Recommendation: As shown in Figure 4-4 and the associated table, the method with TOD blocks performs much better than the Daily Average method. And the Rolling methods perform a bit better than the TOD-block method. As a result, we recommend using the rolling hourly approach. The complex rolling spline approach works slightly better than the two-part approach. Despite this slight accuracy advantage, we recommend the two-part approach because it is much simpler, it is easier to implement, and it is much easier to understand.

ROLLING TWO-PART MODEL: EXPLANATORY FACTOR CASCADE

Figure 4-5 shows a cascade of statistics for the rolling hourly Two-Part model as groups of explanatory factors are added sequentially. The chart shows the MAPE value for each hourly model and the associated table shows the average of these values across hours.

The first model which includes only the calendar-based factors and does not include any weather variables is not shown in the graph. The second model adds TD1 and HD1 variables for low powered degrees. The third model adds the TD2 and HD2 variables for higher powered degrees. Then Lag HD and TD values are added. This is followed by calendar and weather interaction variables. The last step, which adds a first order autoregressive error term is not shown in the graph.

FIGURE 4-5: ROLLING TWO-PART MODEL, EXPLANATORY FACTOR CASCADE STATISTICS



Rolling Model Components	Average MAPE
Month, DayType, Hols	10.31%
Add THI1, HD1	4.08%
Add THI2, HD2	3.64%
Add Lag24 DD	3.10%
Add Lag48 DD	3.02%
Add Long Lags	2.92%
Add Month Trends	2.87%
Add WkEnd Shift	2.86%
Add Spring/Fall Shifts	2.77%
Add Hot/Cold Lag Offsets	2.66%
Add Wind * HD,CD	2.58%
Add Clouds * HD,CD	2.41%
Add Clouds	2.37%
Add Covid Vars	2.25%
Add AR1	2.04%

This cascade reveals the accuracy gain that results as each variable group that is added. The chart shows hourly pattern of these accuracy impacts. For example, the large gap toward the bottom (from light blue to red) reflects the influence of adding the cloud interaction variables. These have the greatest impact in the day-time hours (between HE9 and HE18), reducing the mid-day MAPE values from 3.5% to 3.0%.

TEMPERATURE-HUMIDITY INDEX CONSTRUCTION

There are a variety of THI-type indexes that have been used over the years. There are formulas that use drybulb and wetbulb temperatures, drybulb and dewpoint temperatures, and drybulb and humidity. The index currently used by PJM falls into the third category and is shown on the left-hand side of Figure 4-6. This formula has some nice properties, in that humidity interacts with temperature. As a result, the higher the temperature, the more important an extra percent of humidity becomes.

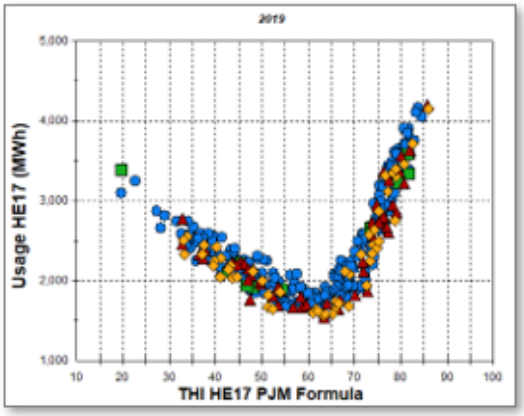
Although it is not obvious, this formula has the unfortunate effect of compressing the temperature variable rather than creating a higher "feels-like" type of variable. This is seen in the four cases that are shown in Figure 4-6. All cases have a drybulb temperature of 90 degrees. In the first case, humidity is at 40%, which is about as low as humidity gets in the DPL zone in summer months. At 40% humidity, the PJM formula gives a THI value of 79.4. As humidity levels rise above 40%, THI values increase and hit their highest value at 100%, at which point the THI value is the same as the drybulb temperature.

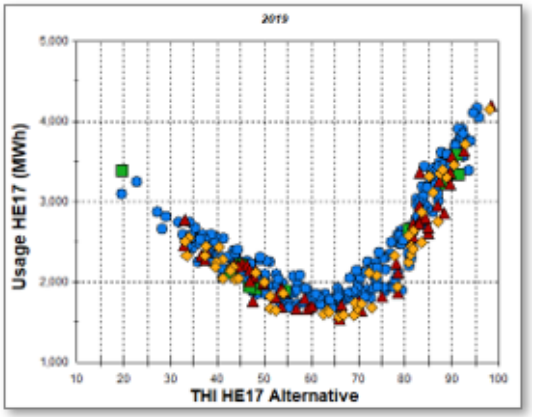
The alternative formula works differently. At humidity levels rise above 40%, the THI temperature goes above 90 degrees. At the extreme of 90 degrees and 100% humidity, the THI reached a level over 100 degrees.

FIGURE 4-6: THI FORMULAS AND HE17 SCATTER PLOTS

	Current PJM Formula T - .55 * (1 - Hum/100) * CD58			
	Case 1	Case 2	Case 3	Case 4
T (°F)	90.0	90.0	90.0	90.0
Hum (%)	40.0	65.0	90.0	100.0
THI	79.4	83.8	88.2	90.0

	Recommended Formula T + .55 * (Hum/100 - .4) * CD58			
	Case 1	Case 2	Case 3	Case 4
T (°F)	90.0	90.0	90.0	90.0
Hum (%)	40.0	65.0	90.0	100.0
THI	90.0	94.4	98.8	100.6





The compression effect is clear in the graphs, which show scatter plots for HE17 loads against the HE17 THI value. The scatter plots show about 4 years of data from mid-2017 to mid-2021. The cold sides of the two graphs (temperatures below 58 degrees) are identical because the humidity component only impacts warmer temperatures. In the left-hand chart, which uses the current PJM formula, THI cooling impacts appear to begin a bit before 70 and the highest THI value is at 85, giving a 15-degree range. With the alternative formula, the highest values are at about 98, giving close to a 30-degree range. This makes it easier to see the difference between low powered degrees (70 to 80 using the alternative definition) and the high-powered degrees (degrees above 80).

By choosing different base temperatures for the two approaches, the two formulas can be made to work about the same in terms of accuracy. But the alternative definition makes it easier to visualize the use of multi-part TD variables on the hot side. Also, we believe that the alternative definition is easier to understand, because it is consistent with our intuition that higher levels of humidity make it feel hotter than the drybulb air temperature. As a result, the following recommendation is based more on convenience and consistency with common sense than performance improvement.

Recommendation: Use the alternative THI formula shown above. As time allows, optimize the parameters in this formula (the .55, the -.4, and the 58-degree base for the temperature interaction), noting that the best values of these parameters may vary across zones. Also, as time allows research alternatives using the same type of interactive specification with the more stable measures of humidity, like dewpoint temperature and moisture content.

WIND/TEMPERATURE INTERACTIONS

PJM currently uses a Wind-Adjusted Temperature (WWP) variable. It is defined as follows:

- WWP = T - .5 * Max (Wind – 10, 0)

This variable is used to compute heating degree values, which come into play in the winter for forecasting energy and system peaks. This variable is the only place that wind appears in the modeling. This implies:

- Wind only matters when it is cold
- Wind does not matter until it exceeds 10 MPH
- Beyond 10 MPH, each additional MPH is like a 0.5-degree temperature decline

In terms of the effect of wind on building HVAC systems, there are at least two effects. First, when it is still, there is a thin layer of air surrounding the building that acts like an insulating layer and that is heated when the sun is shining on the building surface.

When it is cold and cloudy, this layer is warmer than the surrounding air. When the wind blows, this layer of insulation is removed, which increases the heating load.

When it is warm this layer is much hotter than the surrounding air on the roof and sunny side of the building. When the wind blows, it removes this superheated layer, which reduces the cooling load.

These effects probably start to be felt by building systems well below 10 MPH.

Second, wind impacts infiltration levels. High levels of wind result in higher rates of air turnover in buildings that are not perfectly sealed. When humidity levels are high, this has the further effect of replacing dry cooler air inside with warmer humid are from outside.

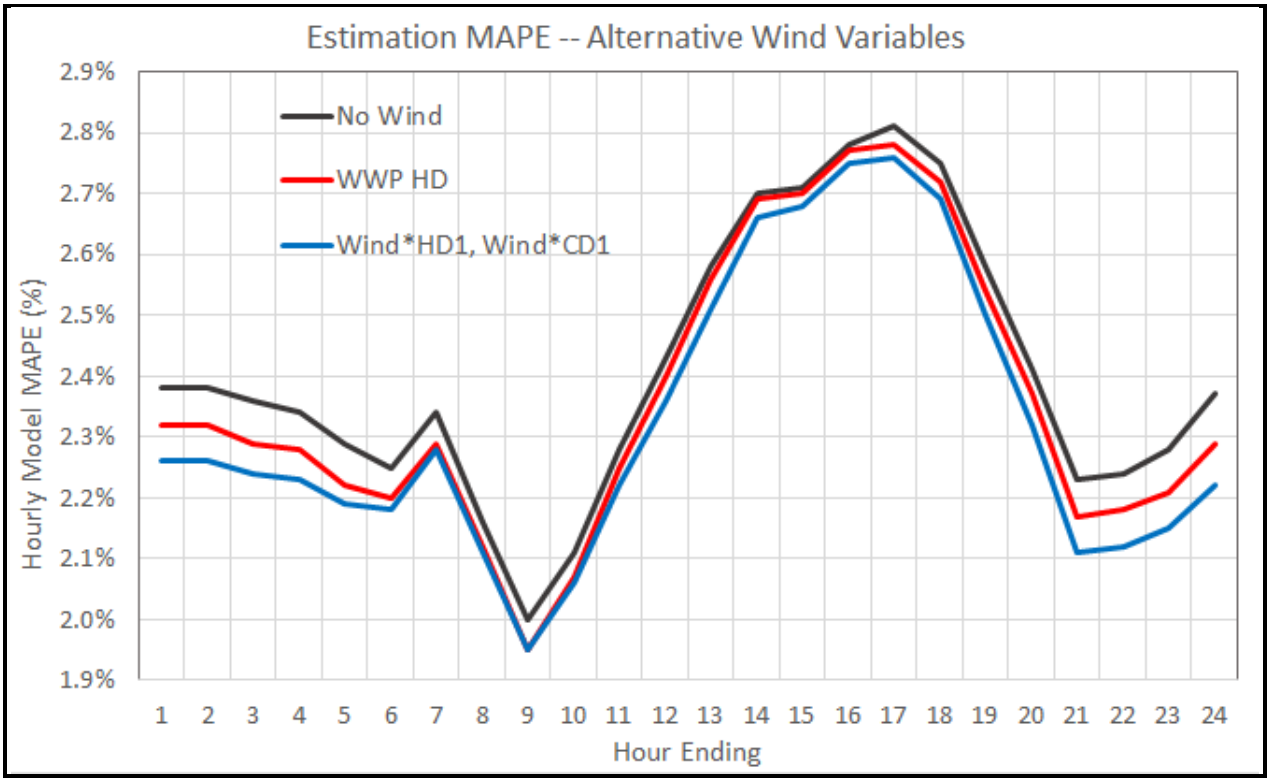
To evaluate this, we estimated models that interact wind speeds with HD and TD variables in each hour. The two variables used are:

- ColdWind = WindSpeed ×HD1
- HotWind = WindSpeed × TD1

On the heating side, the estimated coefficients are negative and significant throughout the day, implying that more wind raises the heating load in all hours when it is cold. The slopes are weaker during the mid-day hours, possibly reflecting the influence of sunlight on building surface temperatures during the day. On the cooling side, coefficients are positive and significant in the night hours and negative and significant in the mid-day hours. During the day, the wind blows the superheated air on sunny building surfaces away, lowering the cooling load. At night, wind causes higher infiltration of warm and possibly humid air, increasing the cooling load.

Figure 4-7 shows MAPE statistics without Wind (black line), with the current wind variable (red line) and the alternative hot side and cold side wind variables defined above.

FIGURE 4-7: IMPACT OF WIND VARIABLES ON MODEL ACCURACY



Inclusion of the cold-side wind variables improves model performance in all hours, with the biggest impacts in the nighttime hours. Use of the alternative variables on both the cold and hot sides result in a further accuracy improvement, with the biggest impacts in the afternoon and nighttime hours.

Recommendation: Use the alternative wind variables on both the cold and hot side. As time allows, optimize the parameters in this formula (the base temperatures in the TD and HD variables that interact with wind speed).

CLOUD COVER/TEMPERATURE INTERACTIONS

Cloud cover variables are not currently included in the PJM models. These are powerful variables, especially in the mid-day and afternoon hours. Cloud cover has three main impacts on utility loads:

On a cold day, clouds interrupt the warming effect of solar radiation on building surfaces. This will result in higher electricity use by electric heating equipment and circulating fans for central heating systems.

On a hot day, clouds interrupt the warming effect of solar radiation on building surfaces. This will result in lower electricity use by electric cooling equipment.

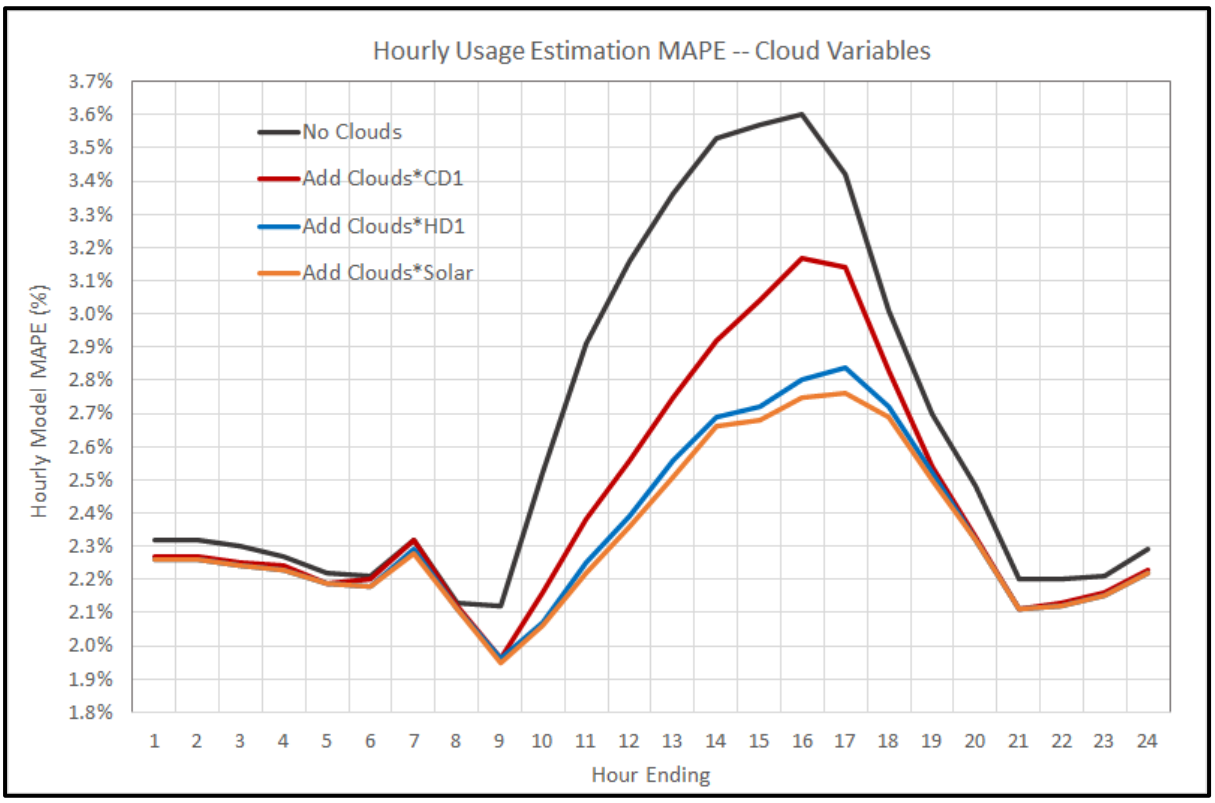
During day-time hours, clouds reduce generation levels for behind the meter solar systems, which will increase the proportion of usage supplied by utility generation sources.

In the early work on this project, we estimated models using utility load, and the third effect was large (as big as 200 MW) and significant. This is shown in the explanatory factor cascade presented above. However, as we will see below, when the explanatory variable is usage (end-use consumption) rather than utility load, the third effect is likely to be small.

Clouds have a further effect of moderating the decline in air temperature at night. But this effect is captured by the measured temperature variable.

Figure 4-8 shows MAPE statistics with usage (reconstituted load) as the variable to be explained. Hourly accuracy statistics are shown for models without Clouds (black line), models with clouds interacted with warm temperatures (red line), and models with clouds interacted with both warm and cold temperatures (blue line).

FIGURE 4-8: IMPACT OF CLOUD VARIABLES ON MODEL ACCURACY



As Figure 4-8 shows, the impact of clouds on model accuracy occurs mostly in the day-time hours, with the biggest impacts about mid-day. The improvement from the black line (average MAPE = 2.64%) to the red line (average MAPE = 2.43%) shows the impacts of clouds on warm days. The further improvement from the red line to the blue line (average MAPE = 2.34%) shows the further impact of clouds on cold days. The final step to the orange line (average MAPE = 2.33%) shows that clouds interacted with clear-sky solar irradiance have a minimal further effect, as expected.

Recommendation: Use the cloud variables interacting with cooling and heating degrees to account for the impact of clouds on hourly energy usage. As time allows, optimize the parameters in this formula (the base temperatures in the TD and HD variables that interact with cloud cover).

INTERACTING HOURLY MODEL VARIABLES WITH SAE EXPLANATORY FACTORS

The following figure shows an example of an estimated hourly model that is built to include SAE variable indexes. Three daily variables are included in the model.

Cooling Index: Accounts for changes in saturation, efficiency, and utilization of cooling equipment (room air, central air, and heat pumps). This index is interacted with the cooling degree variables

(TD1, TD2, LagTD) and the associated cooling degree interaction variables (Wind, Clouds, Weekend, Spring, Fall, etc.)

Heating Index: Accounts for changes in saturation, efficiency, and utilization of heating equipment (resistance heating and heat pumps). This index is interacted with the heating degree variables (HD1, HD2, LagHD) and the associated heating degree interaction variables (Wind, Clouds, Weekend, Spring, Fall, etc.)

Base (Other) Index: Accounts for changes in saturation, efficiency, and utilization of non_HVAC equipment (water heating, cooking, refrigeration, clothes washing and drying, dishwashers, office equipment, lighting, and miscellaneous). This index is interacted with the Constant, Monthly binary variables, day-of-week binary variables, monthly trends, holidays, and Covid phases.

Figure 4-9 provides as an example, the HE18 model (note: the rolling hourly explanatory factors in the model are labeled as hour beginning 17). The variables that are interacted with the Base Index are highlighted in green. The variables that are interacted with the Heating Index are highlighted in red. The variables that are interacted with the Cooling Index are highlighted in blue.

The variables that have clear backgrounds are not interacted with the SAE index variables. Specifically, the Trend, TrendHD, and TrendCD terms are included to allow the model to pick up any trends in the data that are not explained by the SAE variables.

FIGURE 4-9: EXAMPLE OF ESTIMATED MODEL (HE18)

Variable	Coefficient	StdErr	T-Stat
DayTypes.Intercept_XOther	689.463	20.493	33.643
MonthVars.Jan	-5.379	10.614	-0.507
MonthVars.Feb	-29.739	8.883	-3.348
MonthVars.Mar	-77.148	8.422	-9.161
MonthVars.MarDST	-4.426	2.792	-1.585
MonthVars.Apr	-103.989	10.321	-10.075
MonthVars.May	-88.767	10.386	-8.547
MonthVars.Jun	-67.343	11.844	-5.686
MonthVars.Jul	-16.406	14.683	-1.117
MonthVars.Aug	-21.176	16.810	-1.260
MonthVars.Sep	-53.893	15.671	-3.439
MonthVars.Oct	-81.147	12.993	-6.245
MonthVars.Nov	-32.847	12.326	-2.665
MonthVars.NovDST	-16.495	3.604	-4.577
MonthVars.JanWalk	-1.844	1.361	-1.355
MonthVars.FebWalk	-3.773	1.100	-3.429
MonthVars.MarWalk	-0.718	1.583	-0.454
MonthVars.AprWalk	0.915	1.050	0.872
MonthVars.MayWalk	4.216	1.070	3.940
MonthVars.JunWalk	5.269	1.122	4.695
MonthVars.JulWalk	-0.608	1.049	-0.580
MonthVars.AugWalk	-2.870	0.855	-3.357
MonthVars.SepWalk	-4.592	1.119	-4.104
MonthVars.OctWalk	0.475	1.103	0.431
MonthVars.NovWalk	3.100	1.454	2.132
MonthVars.DecWalk	0.283	1.311	0.216
DayTypes.Monday	39.083	3.532	11.066
DayTypes.Tuesday	34.006	3.565	9.540
DayTypes.Wednesday	33.286	3.572	9.320
DayTypes.Thursday	33.936	3.558	9.537
DayTypes.Friday	25.642	3.552	7.219
DayTypes.Saturday	-12.776	2.736	-4.669

Interacts with XOther

Variable	Coefficient	StdErr	T-Stat
Calendar.MLK	37.283	50.244	0.742
Calendar.PresDay	-19.129	47.730	-0.401
Calendar.GoodFri	-8.112	54.883	-0.148
Calendar.MemDay	-114.256	49.459	-2.310
Calendar.July4th	-134.103	47.159	-2.844
Calendar.LaborDay	-39.744	50.150	-0.793
Calendar.Thanks	-378.458	49.853	-7.591
Calendar.FriAThanks	-127.570	49.667	-2.569
DayTypes.WkBeforeXMas	-7.743	15.597	-0.496
Calendar.XMasEve	-145.364	81.256	-1.789
Calendar.XMasDay	-359.132	50.854	-7.062

Variable	Coefficient	StdErr	T-Stat
Calendar.NYEve	-40.271	66.697	-0.604
Calendar.NYDay	-183.177	46.315	-3.955
DayTypes.WkAfterNewYear	20.083	10.327	1.945
DayTypes.WkDayBeforeHol	22.668	26.707	0.849
DayTypes.WkDayAfterHol	-10.909	17.254	-0.632
DayTypes.Phase1	-78.117	14.309	-5.459
DayTypes.Phase2	90.195	11.040	8.170
DayTypes.Phase3	93.289	12.771	7.305
DayTypes.Phase4	31.587	11.900	2.654
DayTypes.Trend2015	-23.962	4.451	-5.384

Heating Vars **Interacts with XHeat**

Variable	Coefficient	StdErr	T-Stat
HD1.HD1_17	12.198	4.552	2.680
HD2.HD2_17	21.169	2.171	9.751
Lag6.Lag6HD_17	7.148	2.182	3.276
Lag24.Lag24HD_17	4.650	0.729	6.381
Lag24HC.Lag24CD_HD17	-1.440	7.269	-0.198
WkEndDD.WkEndHD17	0.475	0.628	0.757
SeasHD.SpringHD17	-0.543	0.636	-0.854
SeasHD.FallHD17	-0.977	0.700	-1.397
ColdWind.WindHD17	18.443	2.617	7.047
ColdClouds.CloudHD17	36.500	4.051	9.011
Daily.MA10_HDD	1.248	0.841	1.484
Daily.MA28_HDD	0.289	1.299	0.222
TrendDD.Trend_HD17	-0.670	0.314	-2.137

Cooling Vars **Interacts with XCool**

Variable	Coefficient	StdErr	T-Stat
CD1.TD1_17	26.219	4.517	5.804
CD2.TD2_17	8.522	1.778	4.792
Lag6.Lag6CD_17	32.113	2.969	10.817
Lag24.Lag24CD_17	6.928	1.307	5.299
Lag24HC.Lag24HD_CD17	-25.499	9.861	-2.586
WkEndDD.WkEndCD17	-0.237	0.870	-0.272
SeasCD.SpringCD17	-19.997	1.493	-13.391
SeasCD.FallCD17	-15.404	2.052	-7.509
HotWind.WindCD17	-2.640	6.026	-0.438
HotClouds.CloudCD17	-137.085	10.435	-13.138
Daily.MA10_CDD	5.254	1.645	3.195
Daily.MA28_CDD	1.096	3.090	0.355
TrendDD.Trend_CD17	1.298	0.330	3.930

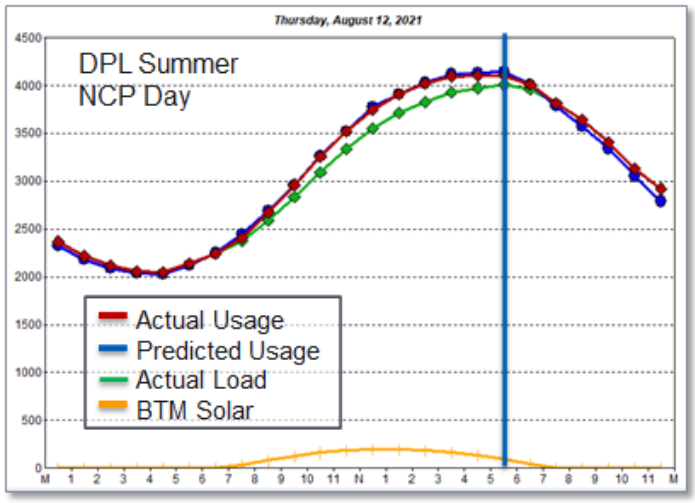
PEAK DAY PREDICTED VALUES AND POST PROCESSING

To evaluate the power of the estimated models on peak days, the following figures focus in on the actual 2021 peak days for DPL and PJM. There are three figures, and each figure shows hourly data for the following four series:

- Actual Usage: This is the estimate of actual usage (reconstituted load), which is measured utility load adjusted for estimated DR effects plus estimated behind-the-meter solar generation.
- Predicted Usage: This is the predicted value from the hourly usage models with explanatory factors interacted with SAE index variables.
- Actual Load: This is the measured DPL zone load, representing the fraction of total usage that is supplied by zone generation resources.
- Solar Generation: This is the estimate of hourly energy supplied by behind-the-meter solar generation.

Figure 4-10 shows the DPL zone peak day, August 12, 2021. Estimated usage on this day is relatively flat between HE16 and HE18. The estimated BTM solar generation, however, is ramping down from 167 MWh to 133 MWh to 94 MWh over these three hours. The hourly models correctly predict that the usage peak occurs on HE17 and that the zone peak load occurs on HE18. In the NCP hour, the model over predicts the zone load by about 46 MWh (1.2%).

FIGURE 4-10: HOURLY MODEL RESULTS – SUMMER 2021 NCP

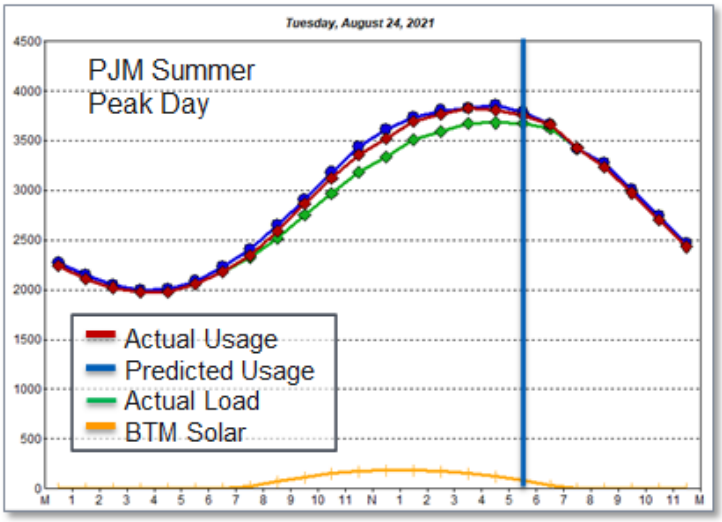


DPL Summer NCP Hour Data	DPL NCP 8/12 HE18
Actual Usage	4,100.3
Predicted Usage	4,146.7
Usage Error	-46.4
Solar_DR	94.3
Actual Load	4,006.0
Predicted Load	4,052.4
Load Error	-46.4

Figure 4-11 shows the DPL zone usage and loads on the PJM peak day, August 24, 2021. On this day, the DPL zone usage peaked in HE16, the measured zone load peaked in HE17, and the PJM peak occurred in HE18. The CP statistics provided to the right of the chart are for HE18, the hour of the

annual PJM peak. In the CP hour, the hourly model overpredicts the DPL zone load by about 27 MWh (.7%).

FIGURE 4-11: HOURLY MODEL RESULTS – SUMMER 2021 CP



DPL Summer CP Hour Data	DPL CP 8/24 HE18
Actual Usage	3,753.6
Predicted Usage	3,781.0
Usage Error	-27.5
Solar_DR	83.6
Actual Load	3,670.0
Predicted Load	3,697.5
Load Error	-27.5

There is a significant difference between the DPL loads on the DPL peak day (Aug 12) and the PJM peak day (Aug 24). Weather statistics for the peak hours on these days are shown in Figure 4-12. The main factor is the difference in average drybulb temperature on these days (93 degrees on the DPL peak day and 89 degrees on the day of the PJM peak day). This difference of nearly 4 degrees persisted throughout the afternoon and evening hours on these days.

FIGURE 4-12: NCP AND CP HOUR WEATHER

Summer Peak Hour Weather Variables	DPL 2021 NCP 8/12 HE18	PJM 2021 Peak 8/24 HE18
AvgDB Temperature (Deg F)	92.7	88.8
Relative Humidity (%)	54.3	53.3
Moisture Content (mmHg)	21.3	19.1
Temp Hum Index (Deg F)	95.4	91.1
Wind Speed (MPH)	11.4	8.4
Cloud Cover (Octas)	0.12	1.6

The difference in loads and the implied coincidence factors are summarized in Figure 4-13. The table focuses on the measured loads. The coincidence factor is the ratio of the CP value to the NCP value. For the summer peak, the actual coincidence factor is 91.6% and the predicted coincidence factor is 91.2%. This are both well below the typical coincidence factor for DPL and are toward the bottom of the range generated by the multi-year weather simulations.

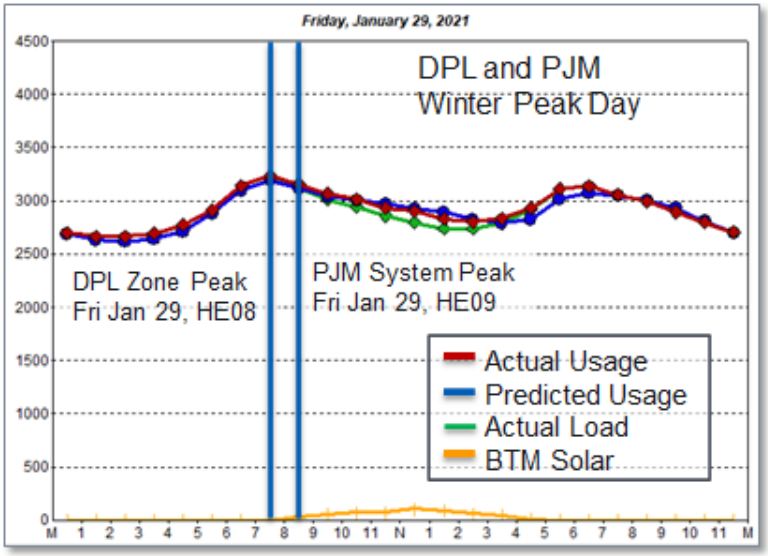
FIGURE 4-13: STATISTICS FOR 2021 SUMMER CP COINCIDENCE FACTOR

DPL Summer Peak Hour Results	Date/Time of NCP	NCP	CP 8/24 HE18	Coincidence CP/NCP
Actual Load	8/12 HE18	4,006.0	3,670.0	91.6%
Predicted Load	8/12 HE18	4,052.4	3,697.5	91.2%
Error	0	-46.4	-27.5	0.4%
Error %		-1.2%	-0.7%	

Figure 4-14 shows the DPL and PJM winter peak day (January 29, 2021). Both peaks occurred on the same day, but at different hours (HE08 and HE09, respectively). The hourly model underpredicted the load in these hours by 39 MWh (1.2%) for the NCP and 43 MWh (1.4%) for the CP. Behind-the-meter solar generation ramped up between the two hours from 2 MWh to 36 MWh.

In terms of coincidence, the hourly model correctly predicts the DPL peak to occur in the hour before the PJM Peak. The predicted winter peak coincidence factor (96.5% is within .1% of the actual measured coincidence factor (96.6%).

FIGURE 4-14: HOURLY MODEL RESULTS – WINTER 2021 NCP AND CP



	DPL NCP 1/29 HE08
Actual Usage	3,232.8
Predicted Usage	3,193.4
Usage Error	39.4
Solar_DR	1.8
Actual Load	3,231.0
Predicted Load	3,191.6
Load Error	39.4

	DPL CP 1/29 HE09
Actual Usage	3,158.0
Predicted Usage	3,115.0
Usage Error	43.0
Solar_DR	36.0
Actual Load	3,122.0
Predicted Load	3,079.0
Load Error	43.0

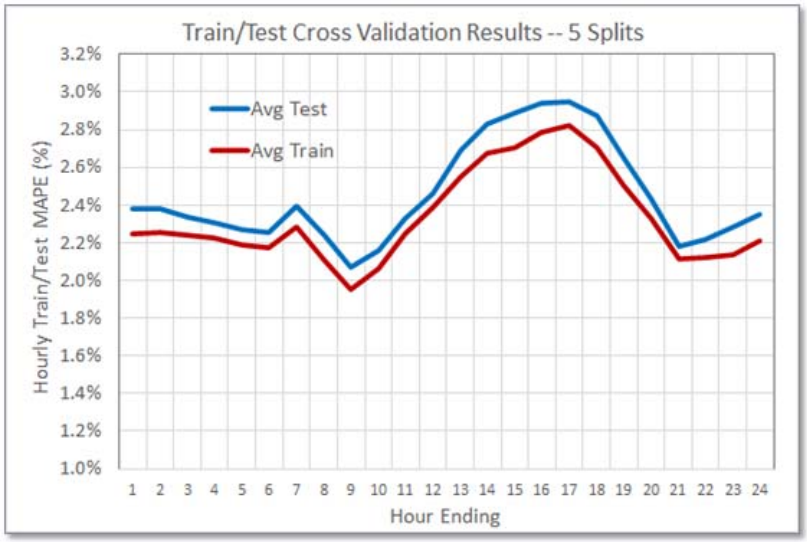
DPL Winter Peak Hour Results	Date/Time of NCP	NCP	CP 1/29 HE09	Coincidence CP/NCP
Actual Load	1/29 HE08	3,231.0	3,122.0	96.6%
Predicted Load	1/29 HE08	3,191.6	3,079.0	96.5%
Error	0	39.4	43.0	0.2%
Error %		1.2%	1.4%	

The accuracy results observed for the 2021 peak days are better than expected given that the average MAPE values for the hourly models are in the 2% to 3% range, depending on the hour. So, it is probably unrealistic to expect results this good for all years. However, the results do show that the hourly modeling approach is capable of explaining NCP, CP, and coincidence factor outcomes. By extension, simulations with alternative actual weather patterns should realistically represent the range of coincidence results that would occur under varied conditions. As part of this project, we did not estimate models for PJM zones other than DPL, nor did we analyze model accuracy for other zones in terms of peak loads and coincidence factors.

MODEL TESTING

The final step with the hourly models is out-of-sample testing. This was performed by running 5 test cases, with each case withholding about 20% of the data. Models were estimated using the training subset of the data in each case and accuracy statistics were computed using the test subset of the data in each of the cases. Figure 4-15 present the train and test statistics averaged across the 5 test cases.

FIGURE 4-15: HOURLY MODEL RESULTS – WINTER 2021 NCP AND CP



	Average	Test1	Test2	Test3	Test4	Test5
All Data Estimation	2.34%					
Average Train	2.34%	2.35%	2.35%	2.33%	2.31%	2.34%
Average Test	2.45%	2.39%	2.48%	2.46%	2.52%	2.41%

Hour	Average Train	Average Test
HR00	2.25%	2.38%
HR01	2.26%	2.38%
HR02	2.24%	2.34%
HR03	2.23%	2.30%
HR04	2.19%	2.27%
HR05	2.18%	2.26%
HR06	2.28%	2.39%
HR07	2.11%	2.24%
HR08	1.95%	2.07%
HR09	2.07%	2.16%
HR10	2.25%	2.33%
HR11	2.39%	2.46%
HR12	2.55%	2.69%
HR13	2.67%	2.83%
HR14	2.70%	2.89%
HR15	2.78%	2.94%
HR16	2.83%	2.95%
HR17	2.71%	2.88%
HR18	2.51%	2.66%
HR19	2.33%	2.43%
HR20	2.11%	2.18%
HR21	2.12%	2.22%
HR22	2.13%	2.28%
HR23	2.21%	2.35%
Average	2.34%	2.45%

As the statistics show, the accuracy for the test cases is close to the estimation (training) accuracy. Averaged across all tests and hours, the test MAPE is about .11% larger than the training MAPE. This indicates that the hourly models are robust (generalize well out of sample). This result (accuracy loss of about .10%) is what we generally expect to see in a model that is well specified in terms of nonlinearities and important interactions and that is not over specified.

5 RESHAPING DEMAND: MODELING TECHNOLOGY IMPACTS

EXTENDED WEATHER SIMULATION FRAMEWORK

The current LTFS forecast process utilizes a multi-year weather simulation framework to construct Cumulative Distribution Functions (CDF) daily energy, daily noncoincident zone peak (NCP), and daily CP (zone load at the time of the daily PJM peak). For each zone, CP models are estimated for daily loads coincident with the Locational Deliverability Area (LDA) peak and coincident with the overall PJM system peak.

The application of the CP and NCP modelling is complicated by the saturation of new technologies (PV and EV in particular) that modify the timing of system energy requirements. In particular, the penetration of behind the meter solar systems is changing both the timing of zone peaks and the coincidence factors across zones. The best way to understand the impact of these changes is by simulating the impact of new technologies on hourly loads. Summarized below are the high-level steps of the recommended Extended Weather Simulation Framework.

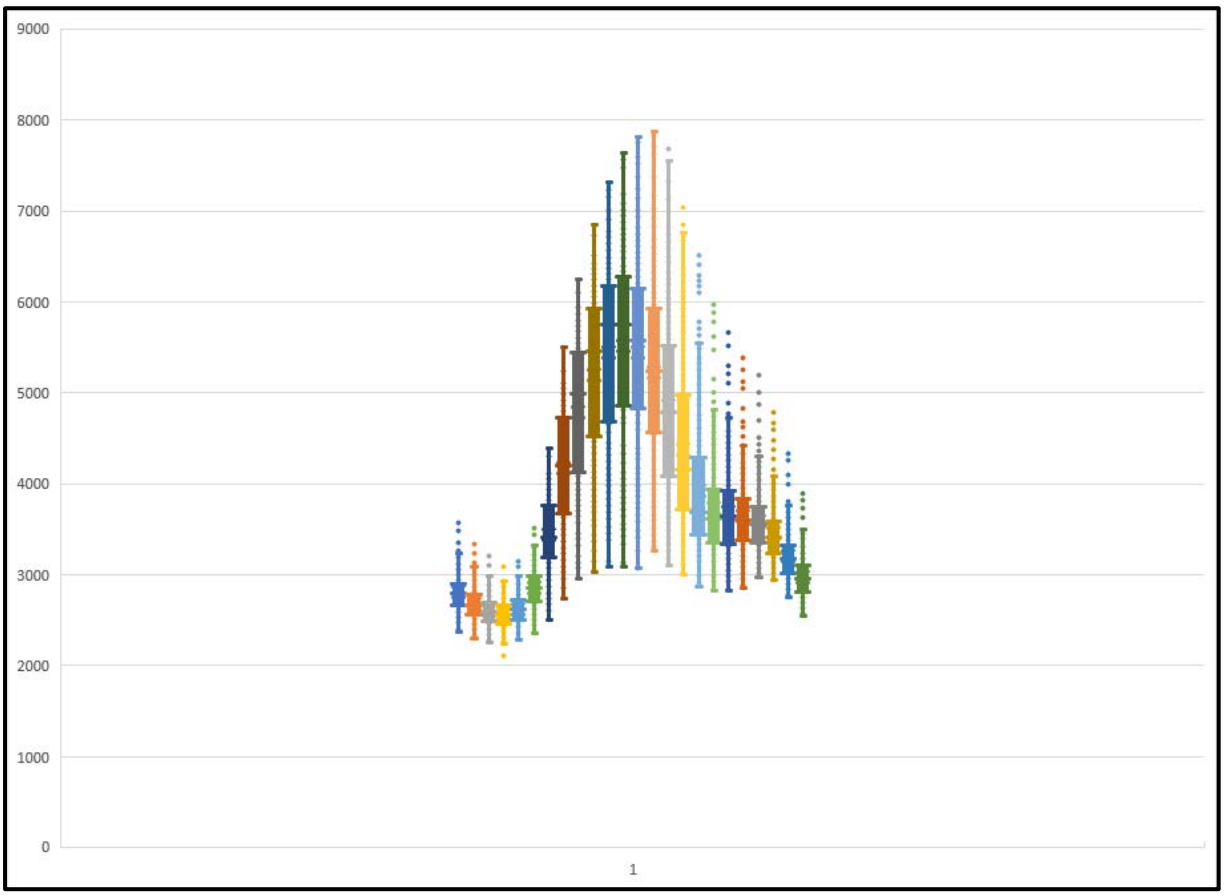
Step 1. Create Weather Forecast Simulation Traces by EDC and Forecast Year. Under this step the existing Multi-year Weather Simulation framework is extended to include hourly Solar Generation Capacity factors that are consistent with the corresponding hourly temperature, wind speed, wind direction, humidity, precipitation, and cloud cover or Global Horizontal Irradiance. The Solar Generation Capacity factors when multiplied by forecasts of embedded solar PV capacity provides an estimate of hourly embedded solar PV generation. These solar PV generation values reduce baseline forecasts of hourly reconstituted loads derived from the hourly load forecast models. The result is a forecast of PJM generation requirements net of distributed solar PV generation.

In a similar fashion, any new technologies that are weather sensitive (e.g., electric heat pumps) should have utilization or capacity factors that are consistent with the hourly weather data.

Step 2. For each EDC, Weather Trace and Forecast Year Simulate EDC-Level Hourly Reconstituted Loads using the Hourly Load models and rotated weather data. For each Weather Trace and Forecast Year Construct PJM Total & PJM Region Hourly Loads by summing across EDCs by Forecast Year, Weather Trace and EDC.

Step 2.a. For PJM Total, PJM Region and for each EDC and Forecast Year, construct hourly Probability Density Functions (PDF) and Cumulative Distribution Functions (CDF) of Reconstituted loads. An example of the PDF for a single EDC and forecast year is presented in Figure 5-1. In this figure each hourly vertical slice represents the PDF of 365 reconstituted loads in that hour.

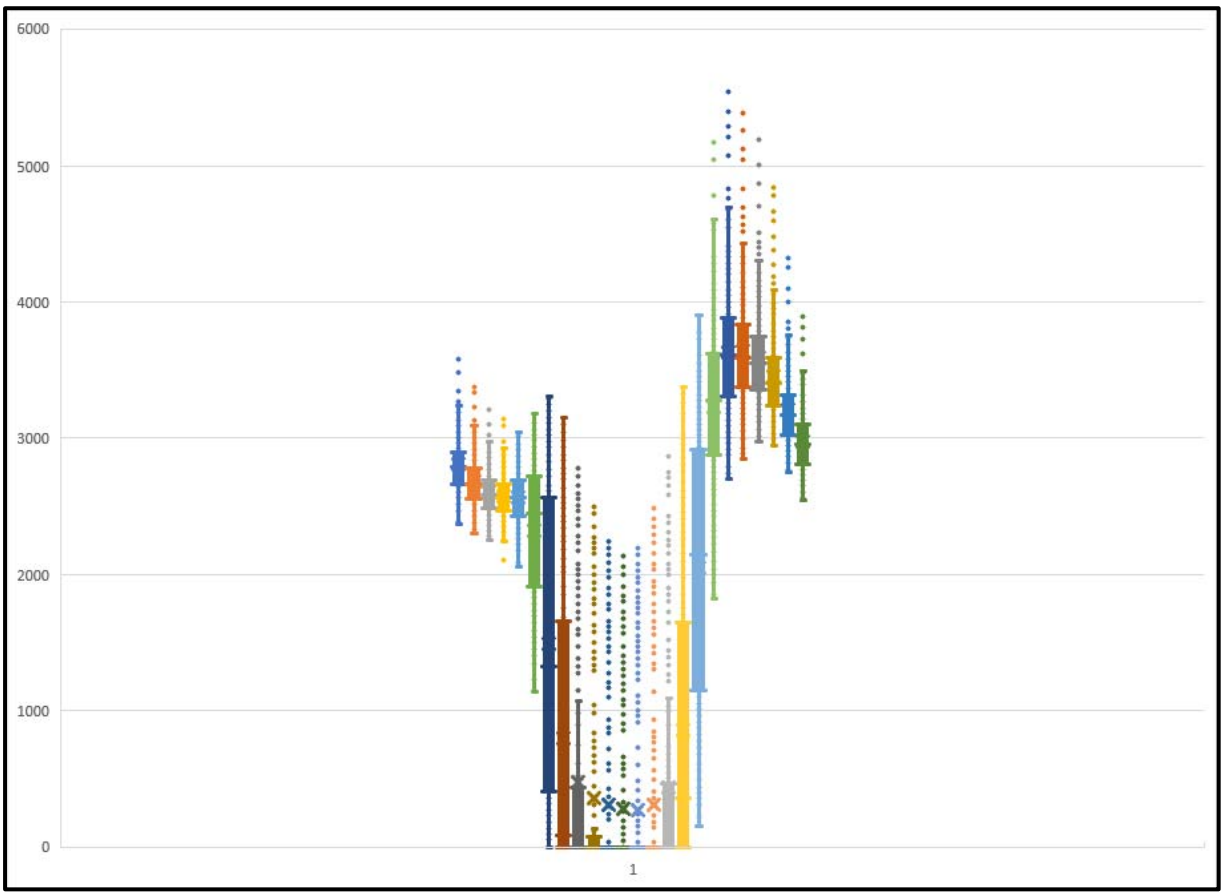
FIGURE 5-1: EXAMPLE PDF OF RECONSTITUTED LOADS FOR A SINGLE EDC AND FORECAST YEAR



Step 3. For each EDC, subtract off simulated EDC-Level embedded hourly solar PV generation Weather Trace and Forecast Year. For each Weather Trace and Forecast Year Construct PJM Total & PJM Region Hourly Loads by summing across EDCs by Forecast Year, Weather Trace and EDC.

Step 3.a. For PJM Total, PJM Region and for each EDC and Forecast Year, construct hourly PDF and CDF of Net Loads (i.e., Reconstituted loads less embedded solar PV generation). An example of the PDF for a single EDC and forecast year is presented in Figure 5-2. In this figure each hourly vertical slice represents the PDF of 365 net loads in that hour.

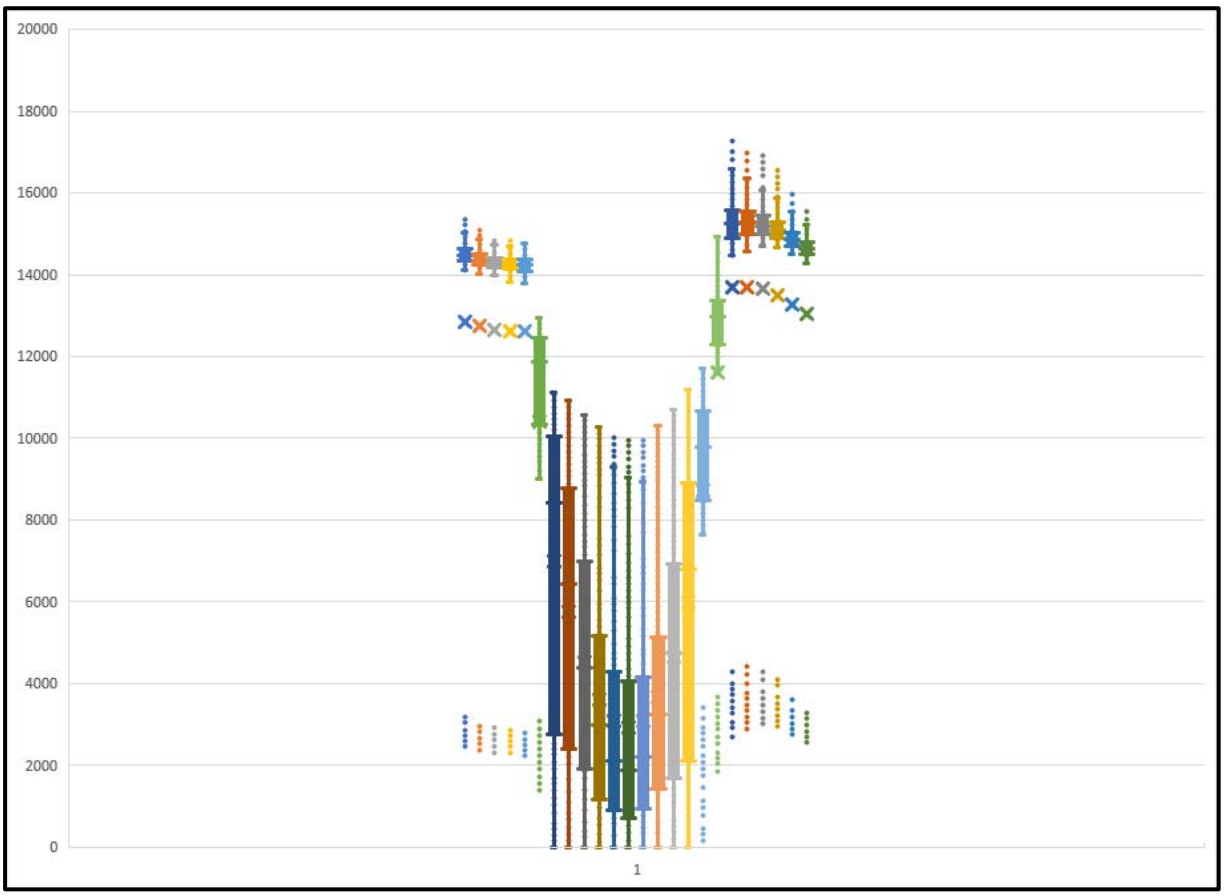
FIGURE 5-2: EXAMPLE SOLAR PV GENERATION ON NET LOADS FOR A SINGLE EDC



Step 4 – Step N. Here N represents the total number of technology impacts that are simulated. For each EDC, Layer in the hourly load impact of the remaining Weather Sensitive and Non-Weather Sensitive Technology Impact Shapes by Weather Trace and Forecast Year. For each Weather Trace and Forecast Year Construct PJM Total & PJM Region Hourly Loads by summing across EDCs by Forecast Year, Weather Trace and EDC.

Step 4.a. – Step N.a. At each step, form PDF and CDF values of the resulting hourly loads by PJM Total, PJM Region, and each EDC and Weather Forecast Year. An example of the PDF for a single EDC and forecast year is presented in Figure 5-3. In this figure each hourly vertical slice represents the PDF of 365 net loads in that hour after residential, commercial, and fleet EV Charging is added in.

FIGURE 5-3: EXAMPLE OF EV CHARGING IMPACT ON NET LOADS FOR A SINGLE EDC



6 MODELING ISSUES

The Market Participants identified several issues to be addressed as part of the study. These issues include:

- Measuring Forecast Accuracy,
- Weather Normalization,
- Capturing Impacts of Energy Efficiency Programs,
- Accounting for Temperature Trends, and
- Large Load Adjustments.

MEASURING FORECAST ACCURACY

Forecast errors for an hourly SAE model can be decomposed into three broad categories:

- Actual weather deviations from "normal"
- Economic growth deviations from forecast
- Other, including SAE saturation and efficiency forecast errors, specification errors, measurement errors, and statistical model errors.

Actual data for the first category (weather) are available on a near real time basis. Actual data for economic growth are available with varying lags and revision cycles. Updated estimates for the SAE inputs are produced annually, but the underlying research that leads to major updates take several years to develop and process, and as a result, we place these in the Other category.

The PJM zone and system forecasts are developed using the weather simulation approach, and the final forecast values for energy, NCP, and CP variables are derived by post processing these data. The best way to judge the accuracy of the underlying model that is used in the weather simulations is to substitute in the actual hourly weather that occurred and, if available, the actual economic variable values. Then compare the model predicted values to the actual values.

For energy and NCP values, this comparison is relatively straightforward. First run the hourly models with actual weather and economic data that are available. Then subtract out the estimated BTM hourly solar generation. Then compute monthly energy and NCP values for each zone and compare these results with the actual measured load values.

For the CP values, more post processing is required to compute the predicted time of the system peak and the predicted hourly zone load values at the CP times. In the end, the idea is to compare what the model would have predicts given actual weather and economics and the outcomes that actually occurred under these conditions. These comparisons are very much like the estimation error comparisons that were made toward the end of the Hourly Models section of this report, where we looked at NCP and CP errors for 2021.

WEATHER NORMALIZATION

The current LTFS forecast process utilizes a multi-year weather simulation framework to construct Cumulative Distribution Functions (CDF) daily energy, daily noncoincident zone peak (NCP), and daily CP (zone load at the time of the daily PJM peak). When this process is run over historical years the midpoint of the CDFs for each concept is taken as the *weather normalize* value.

In general, the power industry utilizes one of two broad approaches for constructing weather normalized loads where each load zone is treated independently of other load zones. In principle, the approaches are designed to provide load patterns under average or typical weather conditions.

Approach 1: Construct Normal Weather. Under this approach, a *normal* weather pattern is first constructed using historical weather data for the load zone under study. The constructed series of normal weather is then pushed through the load zone forecast model to generate a backcast of loads under normal weather conditions. There are several schemes for constructing a normal weather pattern.

- Average weather by calendar day. Under this approach, multiple years of weather are grouped by calendar date (e.g., January 1st, January 2nd, …, December 31st). The daily or hourly averages of each weather concept are then computed. The resulting time series of average data is deemed normal weather.
- An alternative to daily averages is to sort each month of historical weather data from the coldest day to the hottest day. That is, all January days across a year are sorted from the coldest day to the hottest day. The same ranking is developed for each year of available historical weather data. Once the data has been ranked, average values of the ranked data are taken. For the coldest day in January, the algorithm computes the average of the coldest day. The second rank of January data is then used to compute the average of the second coldest day. This continues until all ranked days are averaged resulting in 365 days of average data. The last step is to select a weather pattern from the historical data to allocate the ranked data. For example, if 1987 is selected as the weather pattern year, then the coldest January average is mapped to the coldest day in January 1987. The second coldest January average data is mapped to the second coldest day in January 1987. The process continues until every day in 1987 is assigned data. The resulting Rank & Average time series is then pushed through the load zone forecast model to generate a backcast of loads under normal weather conditions.
- The average approaches described above resulting in average values for all weather concepts. With the proliferation of distributed energy resources like solar PV the resulting weather normalized loads (net of solar PV generation) becomes harder to interpret. The National Renewable Energy Laboratory (NREL) has developed Typical Meteorological Year (version TMY3) weather data that is designed to support building simulations under realistic weather conditions. (See https://nsrdb.nrel.gov/data-sets/tmy). This includes solar radiation data that is consistent with temperature, humidity, wind speed, and wind direction. These data are available for most major weather stations spanning the US. The TMY3 data is constructed by selecting for each month the year that has been deemed the most typical. The actual hourly weather data for the selected year and month is then assigned as the TMY data. For example, the TMY3 data may

use for January the data from January 2010, for February the data from February 2015,…, for December the data from December 2008.

All three schemes work well when the load pattern for a single zone is considered in isolation of other load zones because the construction of normal weather is performed one weather station at a time without consideration of the weather conditions for other weather stations. Thus, it is plausible that normal weather could lead to differences in the timing of and contribution of each load zone to the PJM System and Regional Peaks that are outside historical values. If this approach is used, then of the three schemes the TMY3 data will generate the most realistic net load pattern under *normal* weather conditions.

Approach 2: Multi-year Weather Simulations. Under this approach, multiple years of observed weather data are combined with a load forecast model to backcast loads under alternative weather patterns. The resulting load backcasts are then summarized to determine *weather-normalized* loads. The LTFS constructs for each load zone CDFs of the monthly and seasonal backcast CP and NCP values. The median or 50% value from these CDFs are deemed the weather normalized values.

For multiple zones that are geographically dispersed, construction of **normal weather** patterns that yields a consistent set of "normal" loads across zones is difficult if not impossible. For multiple zones, weather simulations using historical weather patterns yield realistic distributions of loads across load zones. Weather simulations do not ensure that the weather that leads to the 50% or median value CP and NCP for a given load zone may not correspond to the same weather trace that leads to the 50% or median CP and NCP values for all other load zones. As a result, care must be taken when comparing the weather normal CP and NCP across zones.

The introduction of Distributed Energy Resources like solar PV adds complexity and begs the questions: What are "Normal" Loads? The added load volatility associated with distributed solar PV is driving a growing interest on the part of system operators and planners in quantifying hourly load uncertainty. The weather simulation process that PJM employs is well suited to quantifying hourly load uncertainty. We recommend shifting the focus away from developing "normalized" CP and NCP values toward using the weather simulation process to quantify historical and future hourly load uncertainty. The hourly load simulations can also be used to construct distributions of hourly ramp rates that are expected to evolve dramatically with deep penetration of solar PV generation and EV charging.

CAPTURING THE IMPACTS OF ENERGY EFFICIENCY PROGRAMS

Impacts of State and Utility energy efficiency (EE) programs are captured in the model end-use intensities along with new standards and natural occurring efficiency improvements as old appliances are replace with new appliance. There are two components to the end-use intensities – saturations, the share of homes or commercial floorspace that own the end-use and efficiency – the kWh or work output per kWh input. Most primary residential and commercial end-use intensities other than miscellaneous are declining or are flat as increase in end-use stock efficiency is generally increasing faster than saturation.

End-use intensities, a direct input into the SAE models, are derived from the EIA Annual Energy Outlook – saturation and efficiency projections; in the commercial sector, efficiency impacts are embedded in the intensity projections. End-use stock efficiency is derived from an end-use choice model that moves the average stock efficiency based on stock turnover, new purchases, and relative life-cycle costs of competing technology options. In this model, standards work to limit the least efficient options over time while declining costs in more efficient technologies result in greater adoption of the higher efficient technology options.

EIA captures the EE impacts in a couple of ways. First, in the last few years, EIA has made an effort to directly account for state and utility efficiency programs by mapping regional EE program expenditures to end-uses and "rebating" (lowering the cost) of the high-efficient technology options. As a result of the lower cost, more of the high-efficient technology option is adopted. Second, the underlying information on new technologies including number of units sold and associated efficiency information are updated on an on-going basis; this information is derived from annual appliance shipments data. The impact of programs that encourage adoption of more efficient technology such as the Energy Star program and utility incentive programs are partly reflected in the shipments data that in turn are used in calibrating the AEO end-use models.

The SAE estimation process itself also contributes to capturing EE program impacts as the sales and customer data used in estimating the models incorporates past EE program impacts.

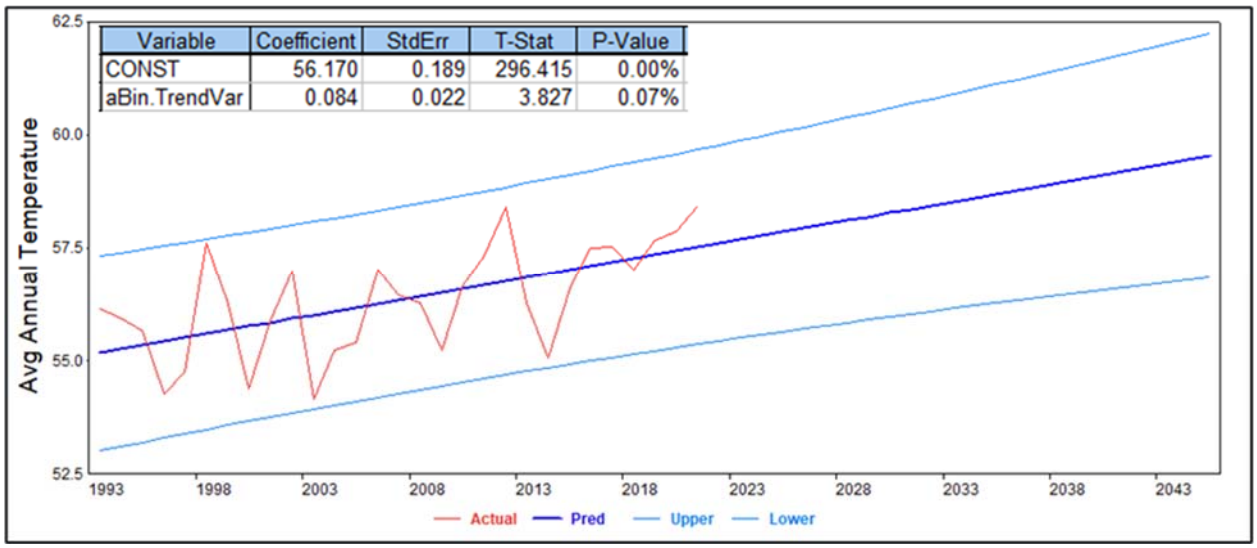
ACCOUNTING FOR TEMPERATURE TRENDS

In electric load forecasts we generally assume that current and future weather conditions will most likely look like the average of the past years. Typically, normal or expected weather is derived as an average of temperatures or degree-days for a twenty to thirty-year period; some utilities will use periods as short as ten-years. Rather than define normal weather conditions, PJM simulates with historical actual temperatures and then calculates normal as the 50% probability outcome. The outcome is approximately the same as if the average temperature profile for the PJM system could be determined.

In recent temperature trend studies, we have found that depending on location, average temperature has been increasing from 0.4 degrees to over 1.0 degree per decade. Our work has been consistent with other temperature trend studies and climate model projections. Giving increasing temperature an average based on the last 20 years would be more representative of 2011 (the mid-year) than 2022.

Figure 6-1 shows the DPL average temperature trend.

FIGURE 6-1: DPL AVERAGE TEMPERATURE TREND



Since 1993, average temperature has been increasing .08 degrees per year or 0.8 degrees per decade. This translates into increasing CDD and decreasing HDD as illustrated in Figure 6-2 and Figure 6-3.

FIGURE 6-2: DPL TRENDED CDD

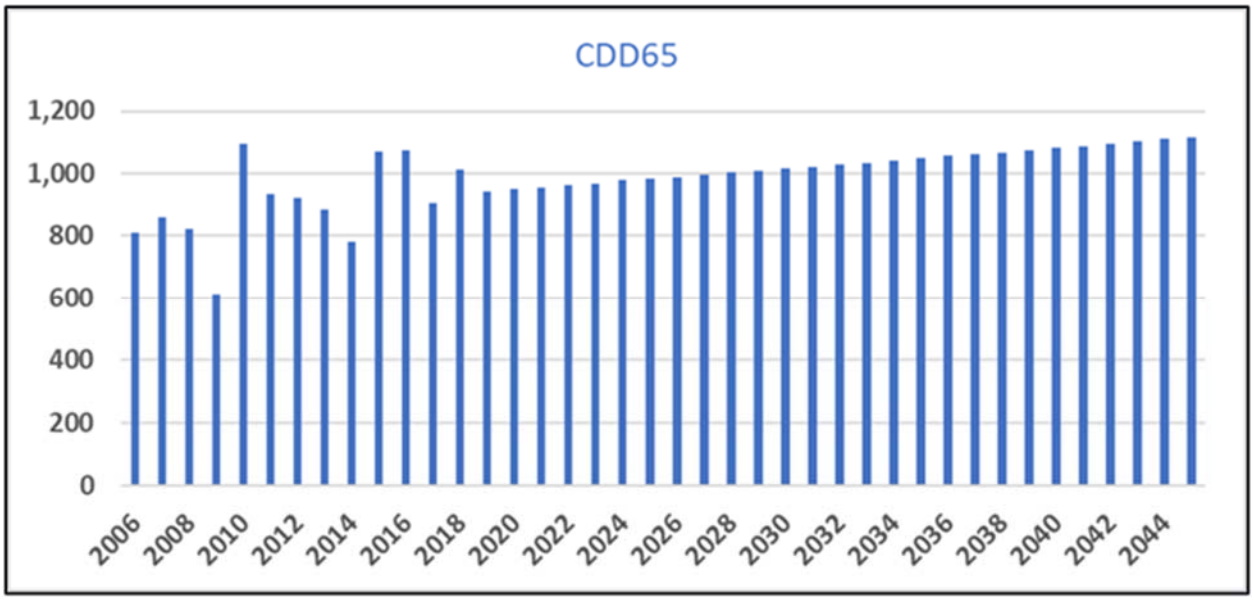
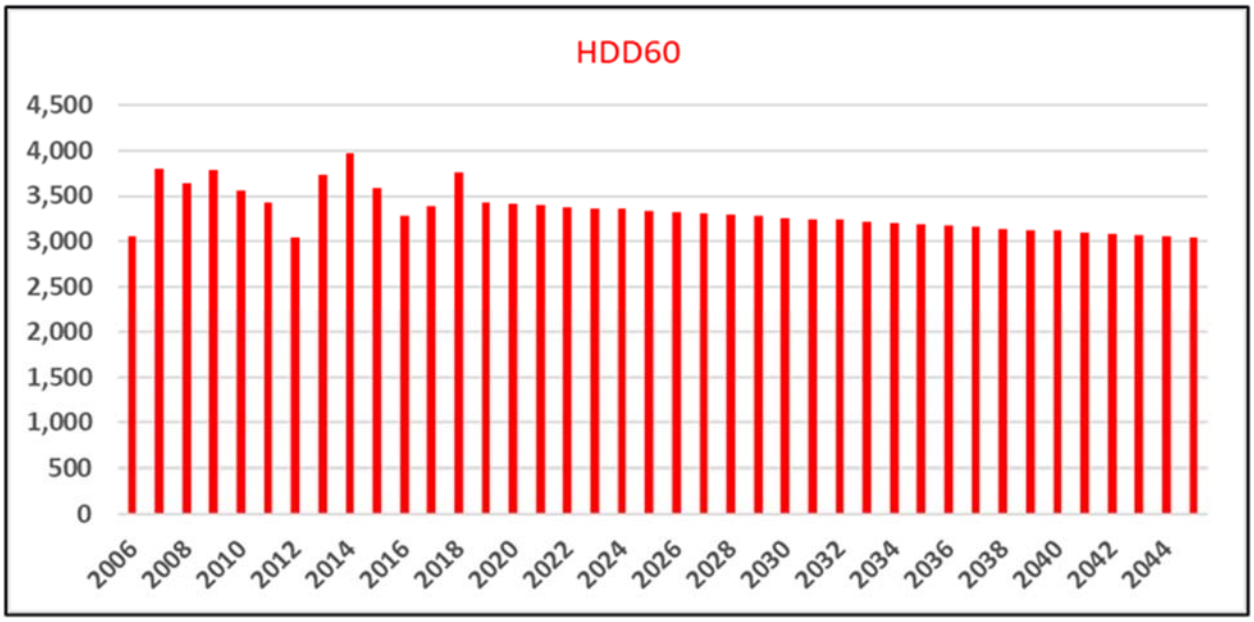


FIGURE 6-3: DPL TRENDED HDD



The weather simulation process and model complexity make it difficult to directly model the impact of increasing temperatures. The approach we recommend is less complex; that is to capture the impact of increasing temperatures with trended normal HDD and CDD in the constructed heating and cooling model indices.

LARGE LOAD ADJUSTMENTS

In the simulation framework, the impact of new technologies such as solar and EVs depends on the load/weather simulation outcome. The earlier section on reshaping loads describes the recommended approach for carrying these technology load adjustments through the forecast horizon. The load forecast may also need to be adjusted for large load additions or losses from a specific customer or group of customers; this would generally be in the industrial sector. If industrial loads adjustments are not too extreme, impacts of load loss or gain can be made to the industrial baseline energy projection that is part of the base-use model index.

One of the largest adjustments has been for data centers in Dominion Zone. Data centers load growth has been enormous – data center loads for just Dominon alone has increased from 1,250 MW at the beginning of 2020 to over 2,500 MW in June of this year. Demand is expected to continue to increase at this pace through 2026. PJM excludes the DOM Zone data center loads from the DOM Zone models and adjust the load afterwards for expected data center load growth. Given the size and growth of data center loads this is the correct approach. PJM relies on Dominion for the first five years of the load projection; this makes sense since Dominon works directly with their data center customers as Dominion plans and builds capacity for future needs.

While the DOM Zone should continue to experience strong data center load growth past the next five years, the rate of growth is likely to slow. Factors that will impact demand growth are transmission and other physical constraints, and demand for more localized data center capacity for services that require faster response time such as 5-G networks, autonomous vehicles, internet of things, and automated manufacturing processes. The long-term forecast will need to be based on historical capacity trends, continuous discussions with utility personnel that are directly involved with data center activities and transmission construction, trade and real estate publication reviews, and organizations that support regional data center development.

7 RECOMMENDATIONS

Throughout the project, we explored several modeling options, discussed issues with the current modeling approach, and ultimately through our work and meetings with PJM staff and Market Participants have developed a set of recommendations that build on the current PJM forecast model. Our recommendations are outlined below:

1. **Replace Annual/Quarterly End-Use Indices with Monthly/Daily Indices**

   Heating, cooling, and base-use load indices can be derived from monthly class SAE models. The SAE models are well documented, used by many utilities for long-term sales and energy forecasting, and are relatively robust in the sense that adding new data and dropping old data does not generally result in significant changes in the model parameters. Indices based on monthly (versus annual models) provide significantly more observations and as a result require fewer years of historical data; resulting in estimated model parameters that will be more representative of the current and forecast periods. Monthly models will also result in stronger heating and cooling coefficients because there is generally more weather variation in monthly data series than in an annual data series.

2. **Continue with Weather Simulation Approach**

   Given the diversity of weather across PJM zones, it is nearly impossible to define a normal daily or hourly weather pattern for the entire system. The current method of developing load distributions from zonal weather simulations represents the best approach for estimating expected long-term demand. Twenty-years of historical weather data with 7 rotations within in each year provides a strong basis for simulating the distribution of load outcomes.

3. **Replace Daily Models (Energy, Zone peak, and Coincident peak) with Hourly Load Models**

   The need to capture the impact of solar, EV, and other technologies that are reshaping demand requires an hourly modeling framework. Replacing the set of zonal daily models with the hourly model described in the report will meet this need. PJM should utilize the hourly rolling weather approach with two-part heating degree and cooling degree variables. PJM should interact these weather variables and other hourly model variables with heating, cooling, and base-use indices developed from the SAE models.

4. **Adjust Loads for Solar and New Technologies Through the Simulation Process**

   To correctly account for solar, EVs and other load adjustments, the hourly projections for these technologies should be constructed to be consistent with the weather simulation process. Each load simulation can then be adjusted appropriately to reflect the impact of solar and other weather-sensitive technology adjustments for each simulation. The load impact of EVs and other non-weather sensitive technologies will also need to be adjusted within the simulation process, as the impact of EVs and other technologies on load depends on the net of solar simulation outcome. The adjusted hourly load simulations can then be post-process to derive

zonal adjusted peak and energy and coincident peaks from the aggregation of the net zonal hourly load forecasts.

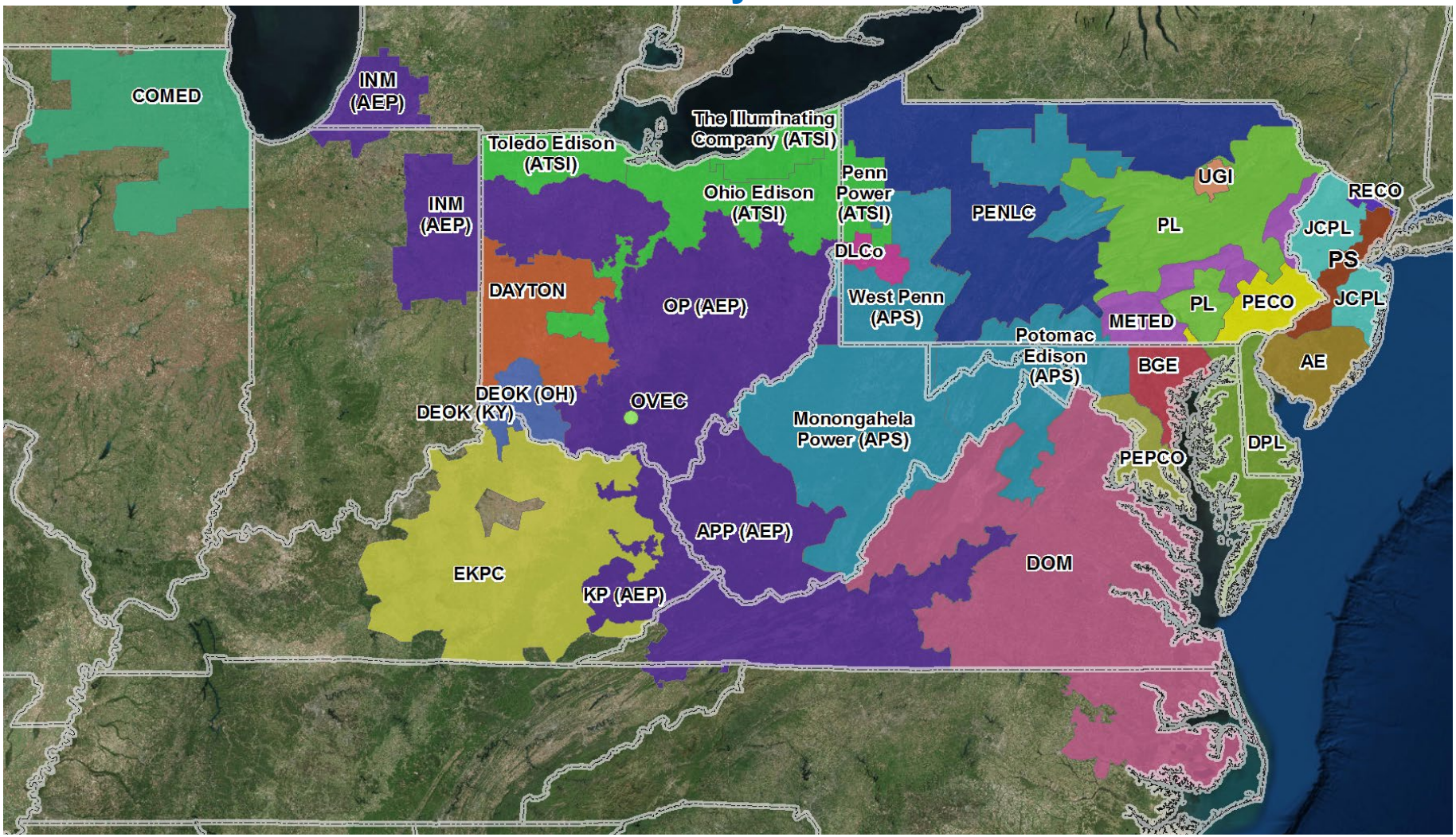
5. Capture Increasing Temperature Trends

Long-term temperature trends should be evaluated for each of the planning zones with results used to adjust cooling and heating indices that are inputs in the hourly load models. We expect to see increasing temperatures across the PJM service area that will contribute to an increase in cooling requirements and a decrease in space heating loads. Zone-level temperature trends can be used to construct trended HDD and CDD that are in turn incorporated into the heating and cooling model indices.

EXHIBIT NO. 47

PJM Load Forecast Report

January 2022



Prepared by PJM Resource Adequacy Planning Department

TABLE OF CONTENTS

	TABLE NUMBER	CHART PAGE	TABLE PAGE
EXECUTIVE SUMMARY			1
FORECAST COMPARISON:			
Each Zone and PJM RTO – Comparison to Prior Summer Peak Forecasts	A-1		29
Each Zone and PJM RTO – Comparison to Prior Winter Peak Forecasts	A-2		31
PEAK LOAD FORECAST AND ANNUAL GROWTH RATES:			
Summer Peak Forecasts and Growth Rates of each Zone, Geographic Region and PJM RTO	B-1	3-28	33
Winter Peak Forecasts and Growth Rates of each Zone, Geographic Region and PJM RTO	B-2	3-28	37
Spring Peak Forecasts of each Zone, Geographic Region and PJM RTO	B-3		41
Fall Peak Forecasts of each Zone, Geographic Region and PJM RTO	B-4		43
Monthly Peak Forecasts of each Zone, Geographic Region and PJM RTO	B-5		45
Monthly Peak Forecasts of FE-East and PLGrp	B-6		47
Load Management Placed Under PJM Coordination by Zone, used in Planning	B-7		48
Distributed Solar Adjustments to Summer Peak Forecasts	B-8a		54
Distributed Battery Storage Solar Adjustments to Summer Peak Forecasts	B-8b		55
Plug-In Electric Vehicle Adjustments to Summer Peak Forecasts	B-8c		56
Adjustments to Summer Peak Forecasts	B-9		57
Summer Coincident Peak Load Forecasts of each Zone, Locational Deliverability Area and PJM RTO (RPM Forecast)	B-10		58

	TABLE NUMBER	CHART PAGE	TABLE PAGE
Seasonal Unrestricted PJM Control Area Peak Forecasts of each NERC Region	B-11,B-12		59
LOCATIONAL DELIVERABILITY AREA SEASONAL PEAKS:			
Central Mid-Atlantic: BGE, MetEd, PEPCO, PL and UGI Seasonal Peaks	C-1		63
Western Mid-Atlantic: MetEd, PENLC, PL and UGI Seasonal Peaks	C-2		64
Eastern Mid-Atlantic: AE, DPL, JCPL, PECO, PS and RECO Seasonal Peaks	C-3		65
Southern Mid-Atlantic: BGE and PEPCO Seasonal Peaks	C-4		66
EXTREME WEATHER (90/10) PEAK LOAD FORECASTS:			
Summer 90/10 Peak Forecasts of each Zone, Geographic Region and PJM RTO	D-1		67
Winter 90/10 Peak Forecasts of each Zone, Geographic Region and PJM RTO	D-2		69
NET ENERGY FORECAST AND ANNUAL GROWTH RATES:			
Annual Net Energy Forecasts of each Zone, Geographic Region and PJM RTO	E-1		71
Monthly Net Energy Forecasts of each Zone, Geographic Region and PJM RTO	E-2		75
Monthly Net Energy Forecasts of FE-East and PLGrp	E-3		77
Annual Plug-In Vehicle Net Energy Forecasts of each Zone, Geographic Region and PJM RTO	E-4		78

	TABLE NUMBER	CHART PAGE	TABLE PAGE
PJM HISTORICAL DATA:			
Historical RTO Summer and Winter Peaks	F-1		79
Historical RTO Net Energy for Load	F-2		81
Weather-Normalized Seasonal Peaks of each Zone, Geographic Region and PJM RTO	F-3		82

TERMS AND ABBREVIATIONS USED IN THIS REPORT

AE	Atlantic Electric zone
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)
Battery Storage	(Also Battery Energy Storage System – BESS) Devices that enable generated energy to be stored and then released at a later time
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
EKPC	East Kentucky Power Cooperative zone (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
OVEC	Ohio Valley Electric Corporation zone (incorporated 12/1/2018)
PECO	PECO Energy zone
PED	Potomac Edison, sub-zone of APS
PEPCO	Potomac Electric Power zone
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
PRD	Price Responsive Demand
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 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

2022 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, distributed solar generation, plug-in electric vehicles, and battery storage for each PJM zone, region, locational deliverability area (LDA), and the total RTO.

- New to the report this year are tables for the peak load impact of battery storage (Table B-8b) and the net energy impact of plug-in electric vehicles (Table E-4).

- Since the 2021 Load Report, PJM made significant revisions to the load forecast model, to better capture granularity in the sector models and weather response in the summer and winter seasons. These enhancements are described in the supplemental report which is available with the other published materials.

- The Non-Weather Sensitive model was estimated with historical data from January 2011 through August 2021, while the Residential, Commercial, and Industrial sector models were estimated with data from 1998 through 2020. Weather scenarios were simulated with data from years 1994 through 2020, generating 351 scenarios.

- The economic forecast used was Moody's Analytics' September 2021 release.

- The 2021 update of Itron's end-use data provides the basis for appliance saturation rates, efficiency, and intensity and is consistent with the Energy Information Administration's 2021 Annual Energy Outlook. PJM obtained additional information from certain zones on Residential saturation rates based on their own load research. Details on zones providing information are presented in the supplement.

- The forecasts of the following zones have been adjusted to account for large, unanticipated load changes (see Table B-9 and the supplement for details):
  - The forecast of the APS zone has been adjusted to account for accelerating load related to natural gas processing plants;
  - The forecast of the ATSI zone has been adjusted to account for the growth in primary metals facilities;
  - The forecast of the COMED zone has been adjusted to account for the implementation of a voltage optimization program;
  - The forecast of the DOM zone has been adjusted to account for substantial on-going growth in data center construction.

- Summer peak load growth for the PJM RTO is projected to average 0.4% per year over the next 10 years, and 0.4% over the next 15 years. The PJM RTO summer peak is forecasted to be 154,381 MW in 2032, a 10-year increase of 5,443 MW, and

reaches 157,689 MW in 2037, a 15-year increase of 8,751 MW. Annualized 10-year growth rates for individual zones range from -0.3% to 2.2%.

- Winter peak load growth for PJM RTO is projected to average 0.7% per year over the next 10-year period, and 0.6% over the next 15-years. The PJM RTO winter peak load in 2031/32 is forecasted to be 141,516 MW, a 10-year increase of 9,414 MW, and reaches 145,220 MW in 2036/37, a 15-year increase of 13,118 MW. Annualized 10-year growth rates for individual zones range from -0.3% to 2.6%.

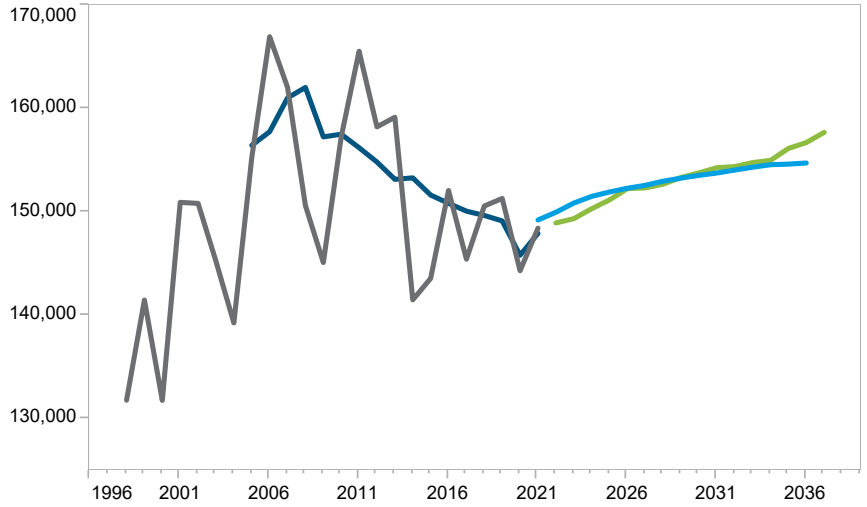
- Net energy for load growth for PJM RTO is projected to average 0.8% per year over the next 10-year period, and 0.7% over the next 15-years. Total PJM RTO energy is forecasted to be 845,133 GWh in 2032, a 10-year increase of 63,815 GWh, and reaches 877,586 GWh in 2037, a 15-year increase of 96,268 GWh. Annualized 10-year growth rates for individual zones range from -0.2% to 3.4%.

- Compared to the 2021 Load Report, the 2022 PJM RTO summer peak forecast shows the following changes for three years of interest:
  - The next delivery year – 2022 -1,028 MW (-0.7%)
  - The next RPM auction year – 2025 -763 MW (-0.5%)
  - The next RTEP study year – 2027 -249 MW (-0.2%)

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 battery storage, additions for plug-in electric vehicles, and prior to reductions for load management impacts.
All compound growth rates are calculated from the first year of the forecast.

PJM RTO

Summer Peak



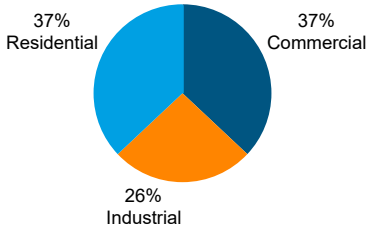
Weather - Annual Average 1994-2020

Cooling Degree Days	*1,075*
Heating Degree Days	*3,851*
Temperature-Humidity Index	*82.7*
Wind-Adjusted Temperature	*11.7*

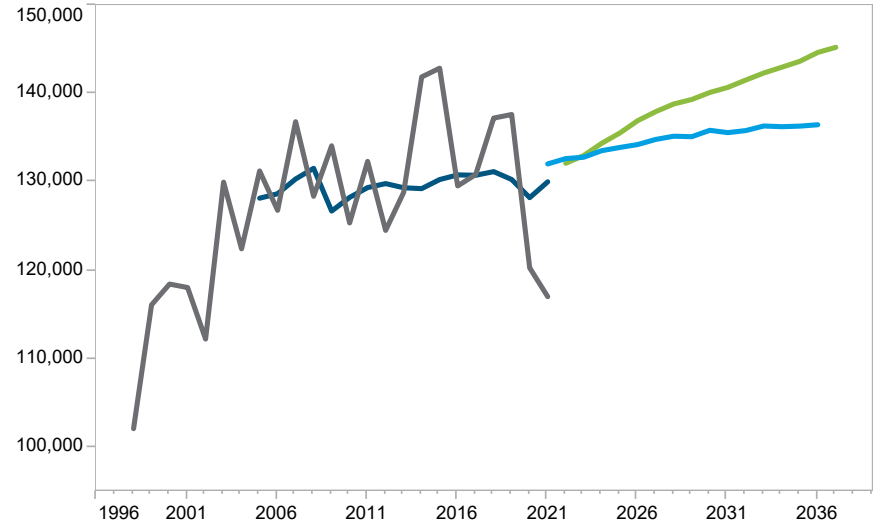
Zonal 10/15 Year Load Growth

SUMMER	0.4%	0.4%
WINTER	0.7%	0.6%

RCI Makeup



Winter Peak



Peak WN peak Forecast 2021 Forecast 2022

LDAs

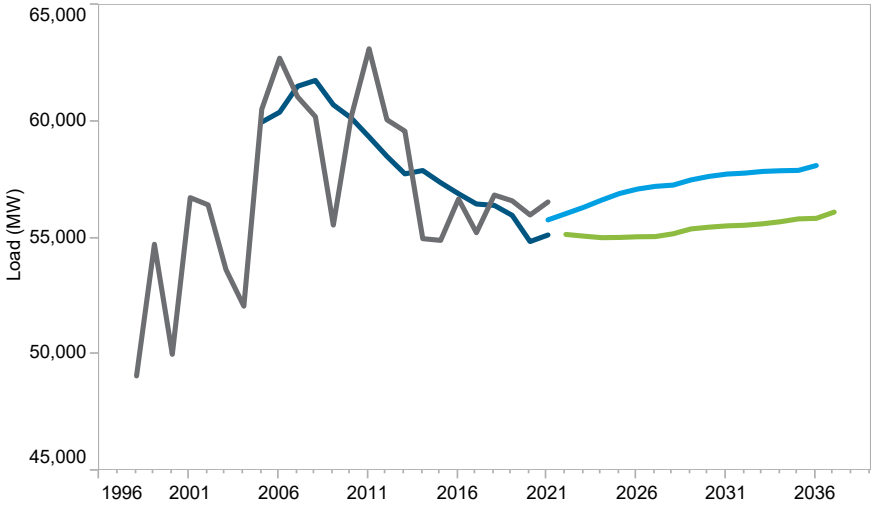
PJM Mid-Atlantic	Central MAAC
Eastern MAAC	Western MAAC
Southern MAAC	PJM West

Zones

AE	DAYTON	JCPL	PEPCO
AEP	DEOK	METED	PL
APS	DLCO	OVEC	PS
ATSI	DOM	PECO	RECO
BGE	DPL	PENLC	UGI
COMED	EKPC		

PJM Mid-Atlantic (MAAC)

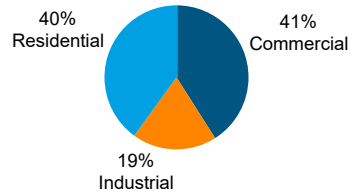
Summer Peak



Weather - Annual Average 1994-2020

Cooling Degree Days	*1,180*
Heating Degree Days	*3,608*
Temperature-Humidity Index	*84.3*
Wind-Adjusted Temperature	*13.2*

RCI Makeup



Zonal 10/15 Year Load Growth

SUMMER	0.1%	0.1%
WINTER	0.4%	0.4%

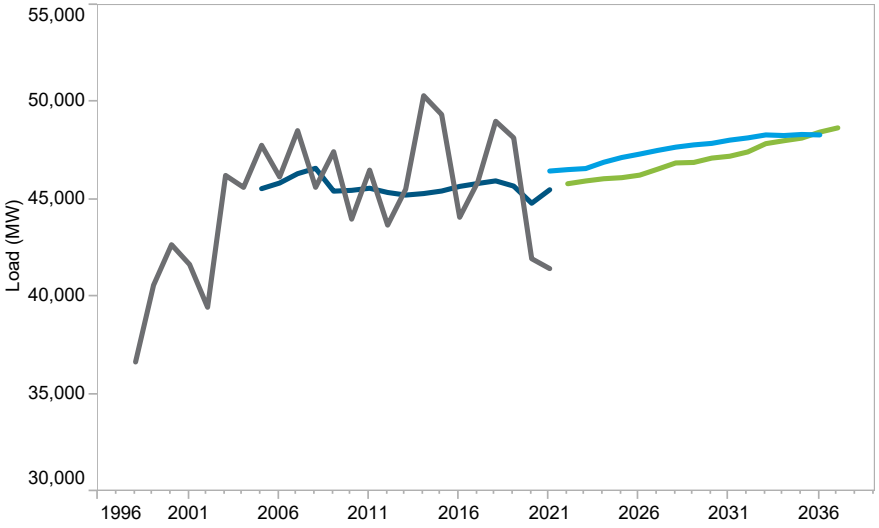
Zones

AE	JCPL	PENLC	PSEG
BGE	METED	PEPCO	RECO
DPL	PECO	PL	UGI

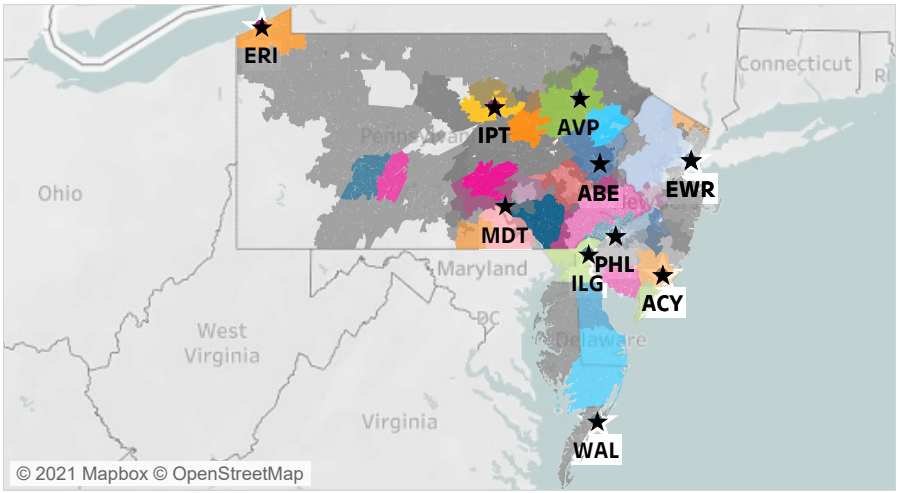
LDAs

E-MAAC	C-MAAC
S-MAAC	W-MAAC

Winter Peak



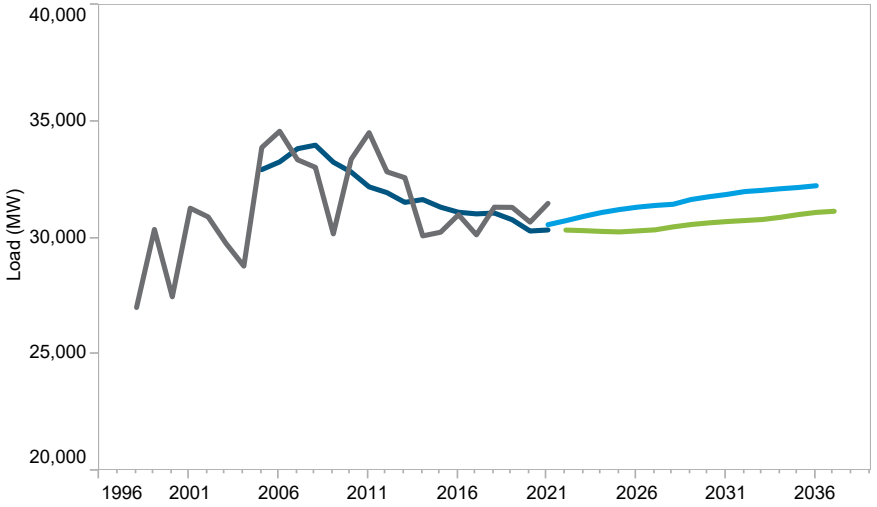
Metropolitan Statistical Areas and Weather Stations



Peak WN peak Forecast 2021 Forecast 2022

PJM Eastern Mid-Atlantic (E-MAAC)

Summer Peak



Weather - Annual Average 1994-2020

Cooling Degree Days	*1,233*
Heating Degree Days	*3,448*
Temperature-Humidity Index	*84.7*
Wind-Adjusted Temperature	*13.3*

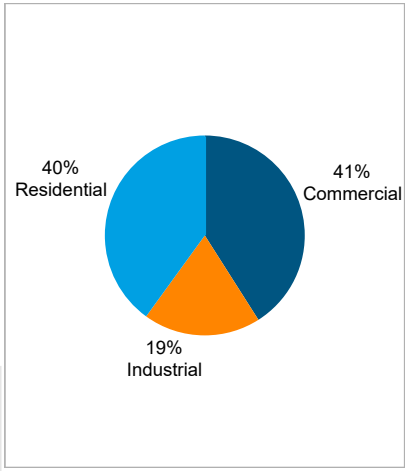
Zonal 10/15 Year Load Growth

SUMMER	0.1%	0.2%
WINTER	0.5%	0.6%

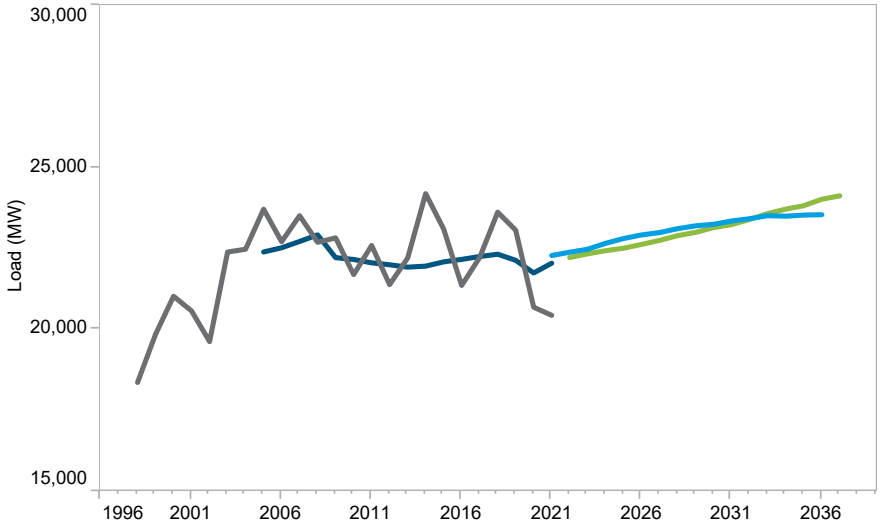
Zones

AE
DPL
JCPL
PECO
PS
RECO

RCI Makeup

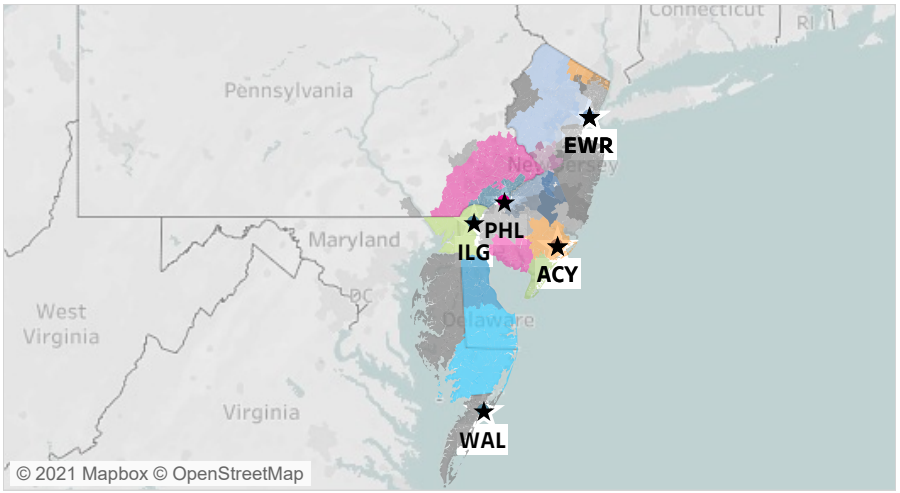


Winter Peak



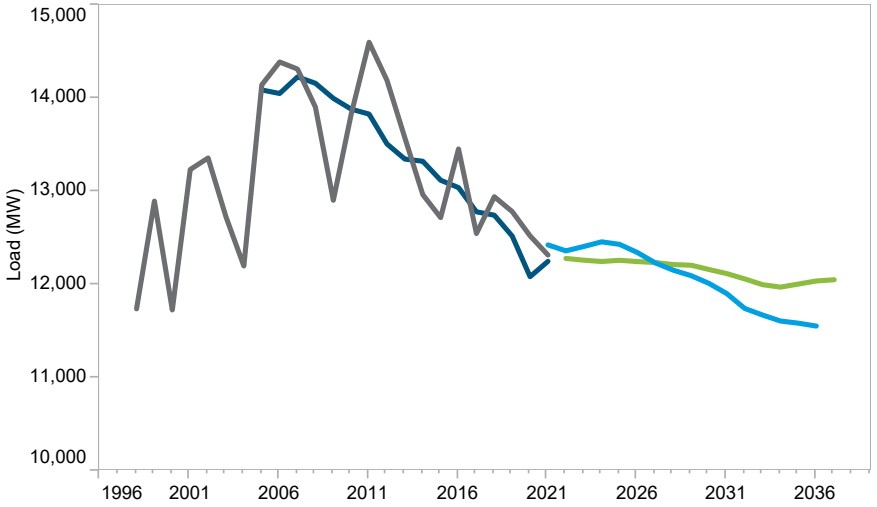
Peak
WN peak
Forecast 2021
Forecast 2022

Metropolitan Statistical Areas and Weather Stations



PJM Southern Mid-Atlantic (S-MAAC)

Summer Peak



Weather - Annual Average 1994-2020

Cooling Degree Days	*1,390*
Heating Degree Days	*3,142*
Temperature-Humidity Index	*85.1*
Wind-Adjusted Temperature	*16.8*

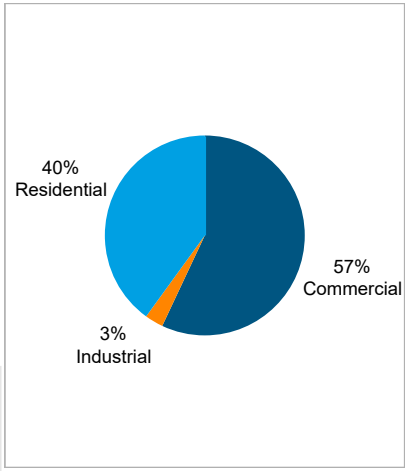
Zonal 10/15 Year Load Growth

SUMMER	-0.2%	-0.1%
WINTER	0.5%	0.5%

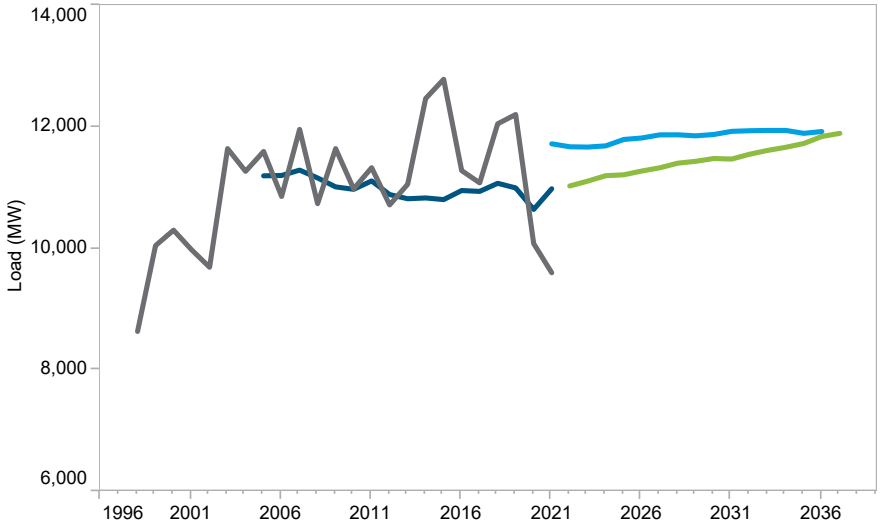
Zones

BGE PEPCO

RCI Makeup

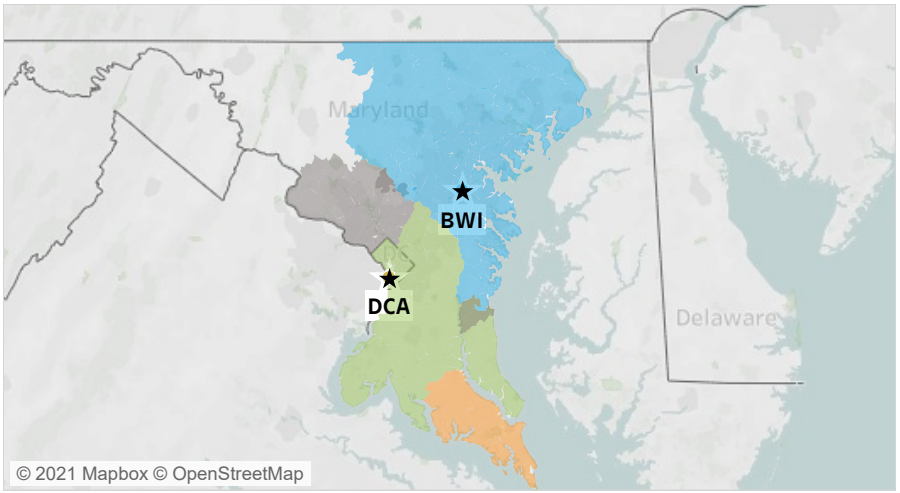


Winter Peak



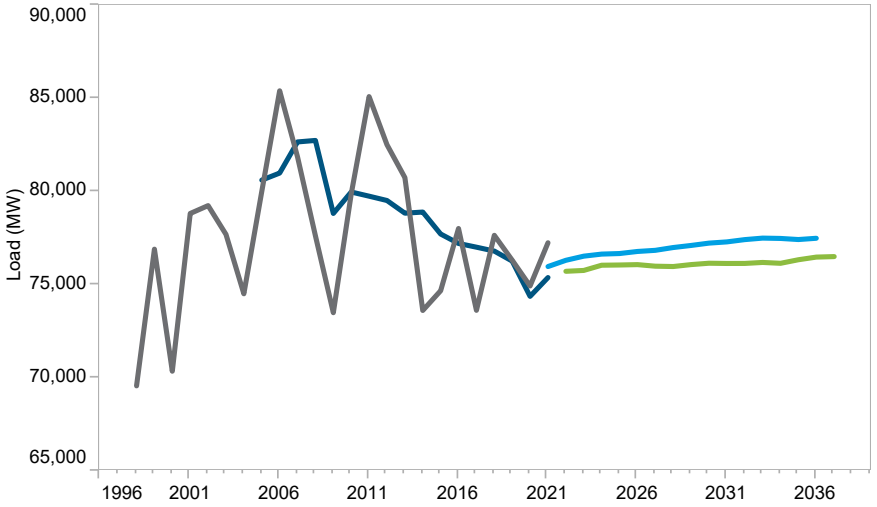
Peak WN peak Forecast 2021 Forecast 2022

Metropolitan Statistical Areas and Weather Stations



PJM Western

Summer Peak



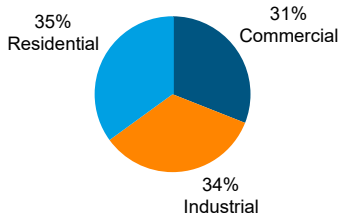
Weather - Annual Average 1994-2020

Cooling Degree Days	*914*
Heating Degree Days	*4,269*
Temperature-Humidity Index	*82.8*
Wind-Adjusted Temperature	*5.8*

Zonal 10/15 Year Load Growth

SUMMER	0.1%	0.1%
WINTER	0.2%	0.2%

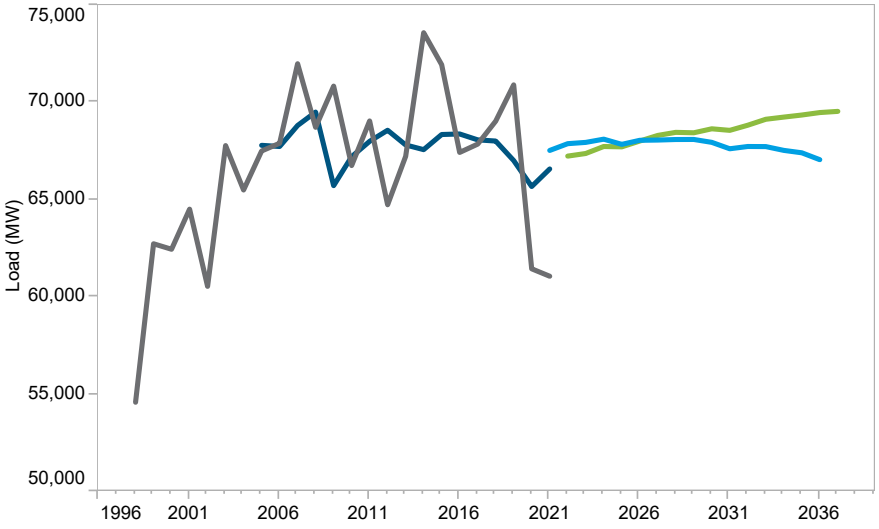
RCI Makeup



Zones

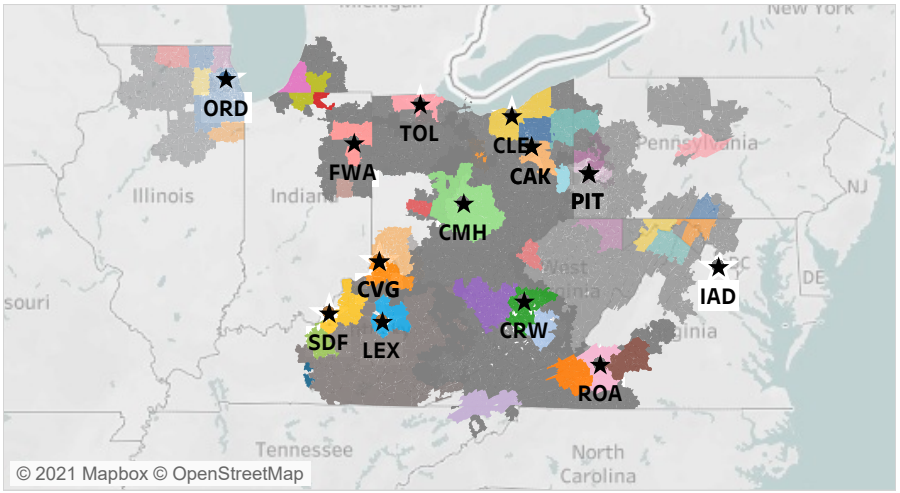
AEP	COMED	DLCO
APS	DAYTON	EKPC
ATSI	DEOK	OVEC

Winter Peak



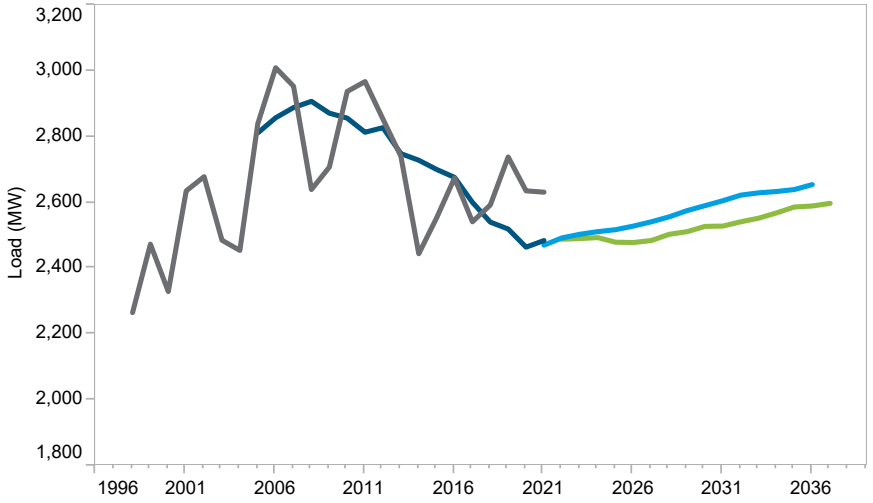
Peak WN peak Forecast 2021 Forecast 2022

Metropolitan Statistical Areas and Weather Stations



Atlantic Electric (AE)

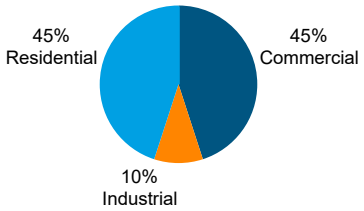
Summer Peak



Weather - Annual Average 1994-2020

Cooling Degree Days	*1,069*
Heating Degree Days	*3,516*
Temperature-Humidity Index	*84.8*
Wind-Adjusted Temperature	*14.7*

RCI Makeup



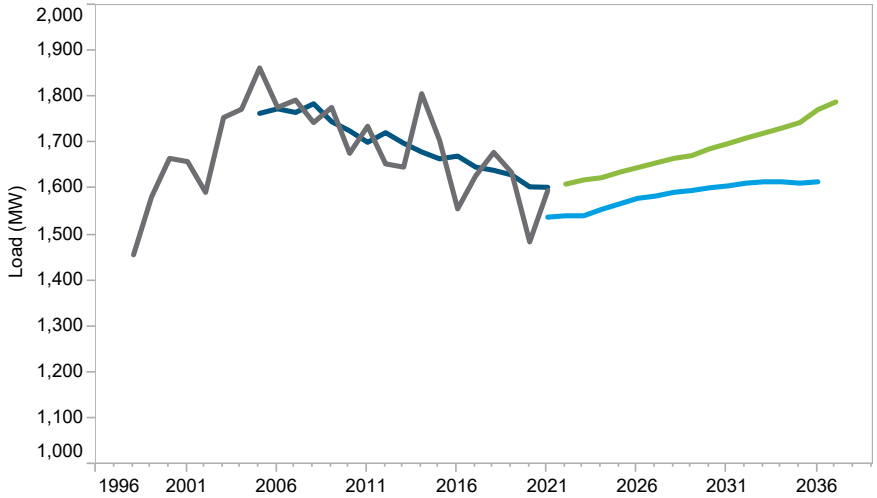
Zonal 10/15 Year Load Growth

SUMMER	0.2%	0.3%
WINTER	0.6%	0.7%

LDAs

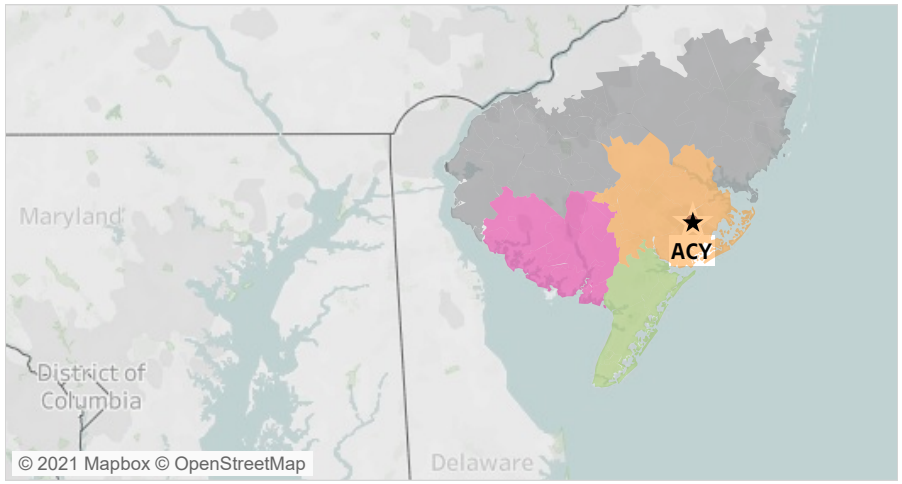
EASTERN MID-ATLANTIC PJM MID-ATLANTIC PJM RTO

Winter Peak



Peak WN peak Forecast 2021 Forecast 2022

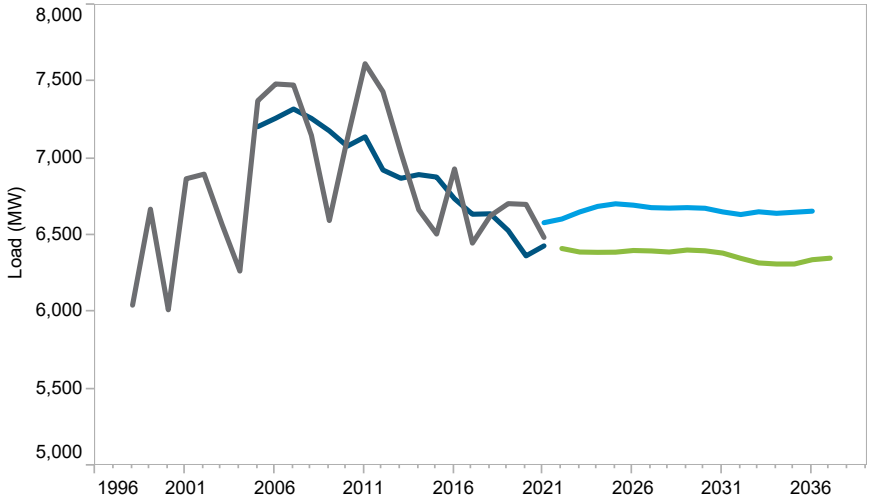
Metropolitan Statistical Areas and Weather Stations



AE - Non-Metro
Atlantic City-Hammonton, NJ
Ocean City, NJ
Vineland-Bridgeton, NJ

Baltimore Gas and Electric (BGE)

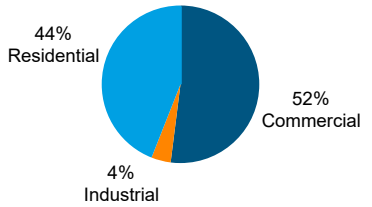
Summer Peak



Weather - Annual Average 1994-2020

Cooling Degree Days	*1,256*
Heating Degree Days	*3,369*
Temperature-Humidity Index	*84.8*
Wind-Adjusted Temperature	*15.9*

RCI Makeup



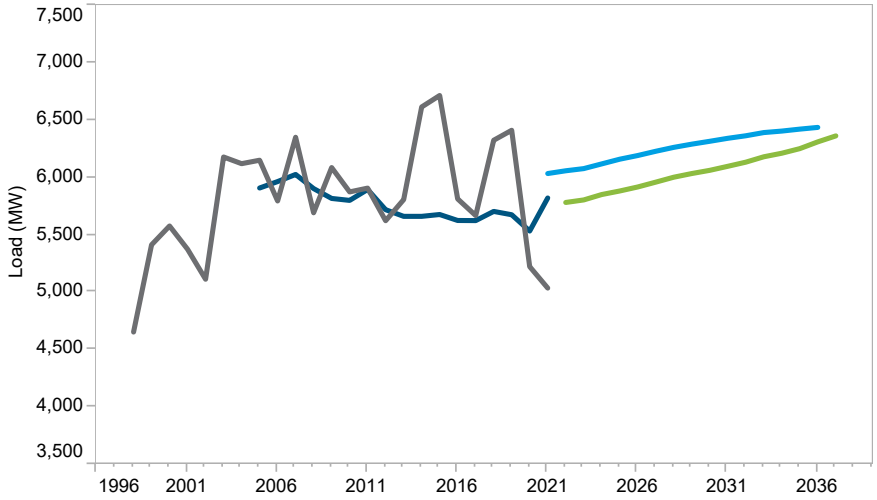
Zonal 10/15 Year Load Growth

SUMMER	-0.1%	-0.1%
WINTER	0.6%	0.6%

LDAs

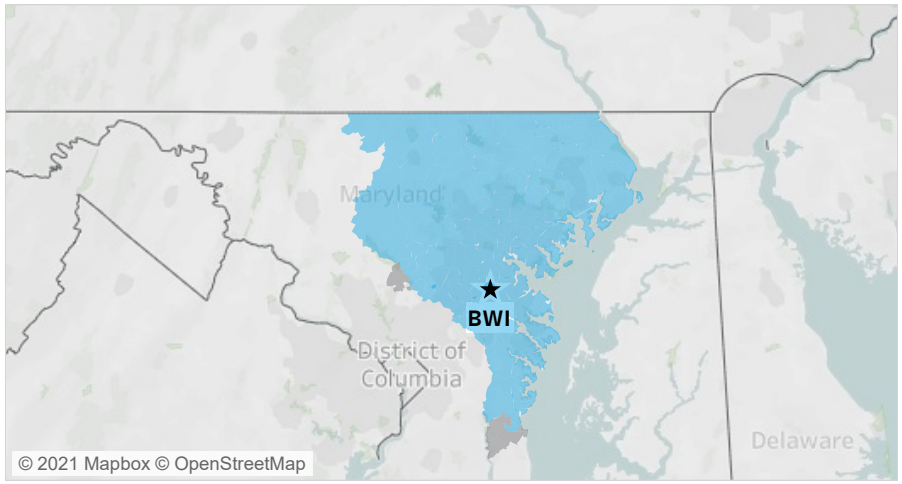
CENTRAL MID-ATLANTIC PJM MID-ATLANTIC PJM RTO
SOUTHERN MID-ATLANTIC

Winter Peak



Peak WN peak Forecast 2021 Forecast 2022

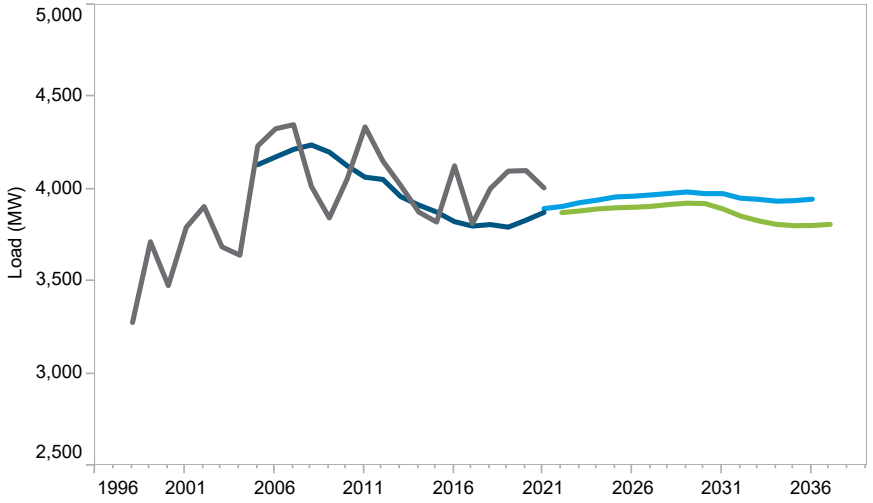
Metropolitan Statistical Areas and Weather Stations



Baltimore-Columbia-Towson, MD
BGE - Non-Metro

Delmarva Power and Light (DPL)

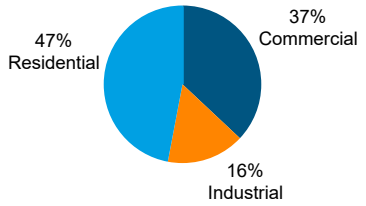
Summer Peak



Weather - Annual Average 1994-2020

Cooling Degree Days	*1,192*
Heating Degree Days	*3,329*
Temperature-Humidity Index	*84.3*
Wind-Adjusted Temperature	*16.0*

RCI Makeup



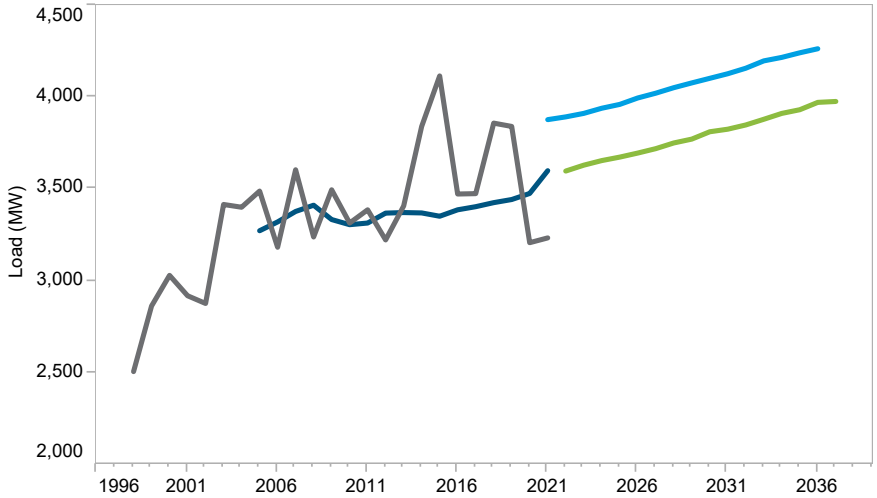
Zonal 10/15 Year Load Growth

SUMMER	0.0%	-0.1%
WINTER	0.7%	0.7%

LDAs

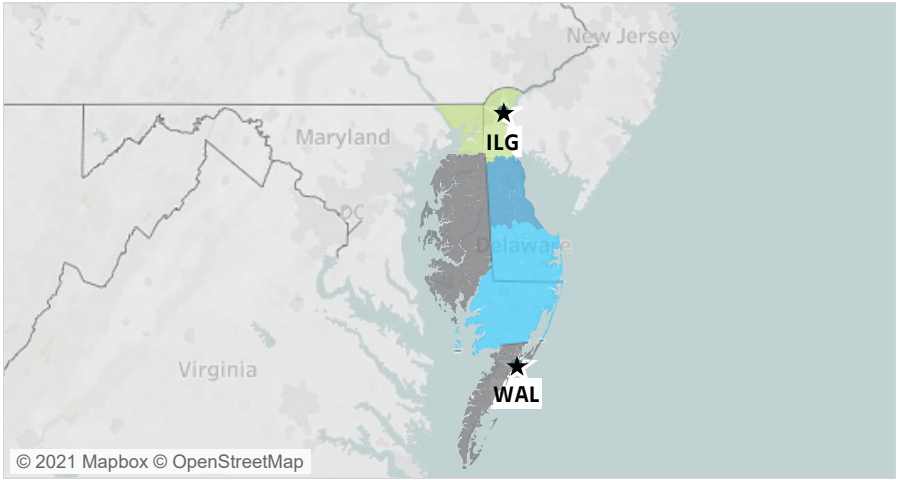
EASTERN MID-ATLANTIC PJM MID-ATLANTIC PJM RTO

Winter Peak



Peak WN peak Forecast 2021 Forecast 2022

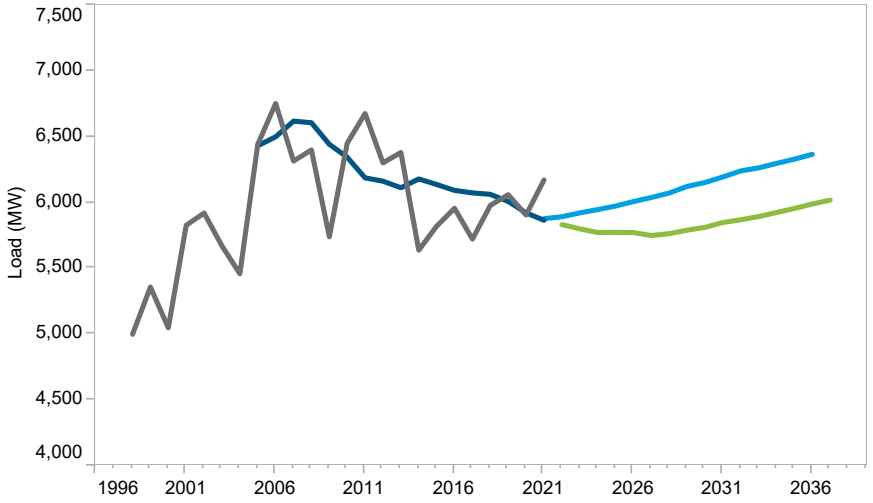
Metropolitan Statistical Areas and Weather Stations



Dover, DE
DPL - Non-Metro
Salisbury, MD-DE
Wilmington, DE-MD-NJ

Jersey Central Power and Light (JCPL)

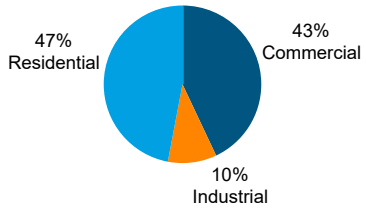
Summer Peak



Weather - Annual Average 1994-2020

Cooling Degree Days	*1,195*
Heating Degree Days	*3,535*
Temperature-Humidity Index	*84.5*
Wind-Adjusted Temperature	*12.4*

RCI Makeup



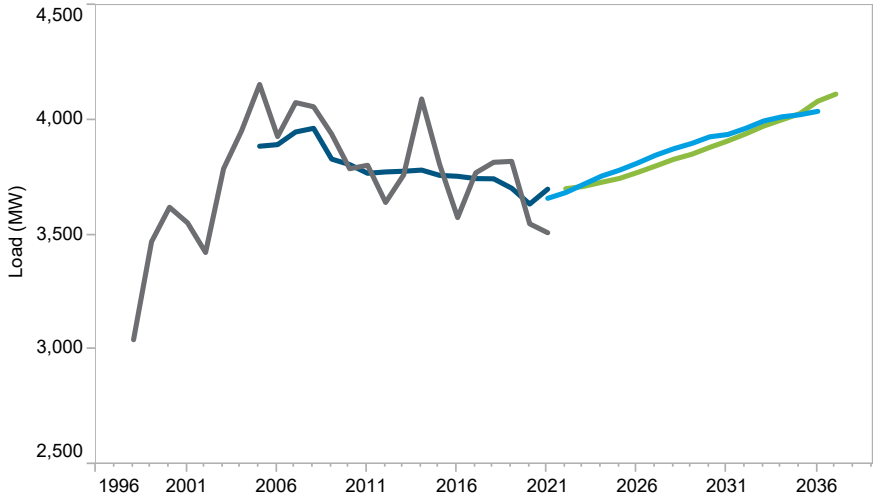
Zonal 10/15 Year Load Growth

SUMMER	0.1%	0.2%
WINTER	0.6%	0.7%

LDAs

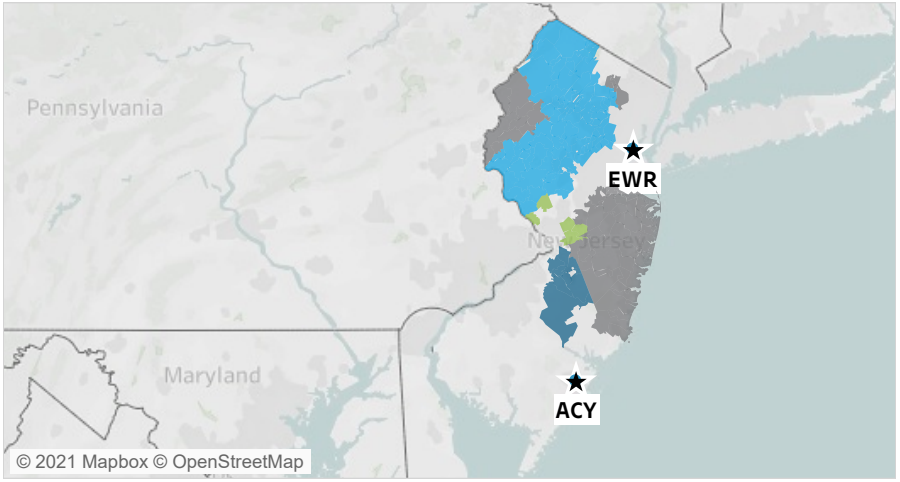
EASTERN MID-ATLANTIC FE-EAST PJM MID-ATLANTIC
PJM RTO

Winter Peak



Peak WN peak Forecast 2021 Forecast 2022

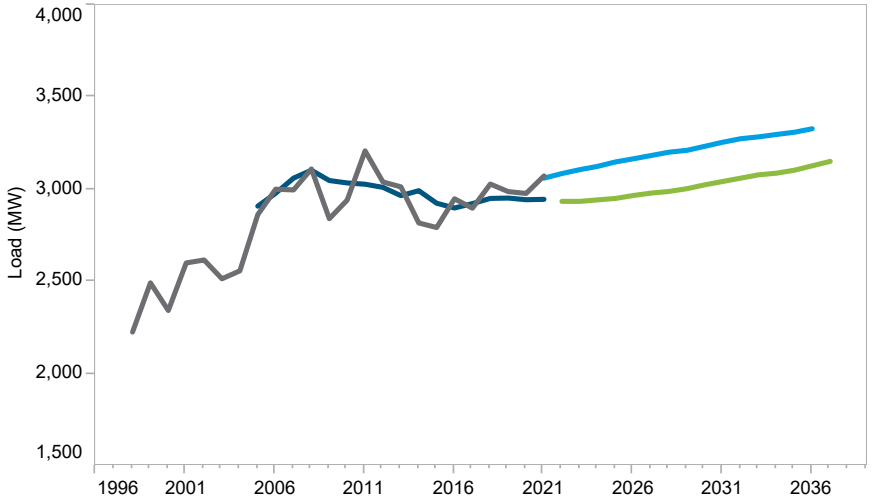
Metropolitan Statistical Areas and Weather Stations



Camden, NJ
JCPL - Non-Metro
Newark, NJ-PA
Trenton, NJ

Metropolitan Edison (METED)

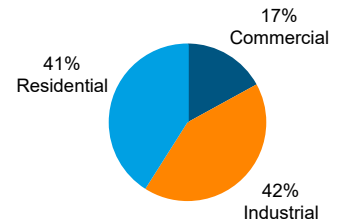
Summer Peak



Weather - Annual Average 1994-2020

Cooling Degree Days	*1,094*
Heating Degree Days	*3,770*
Temperature-Humidity Index	*84.0*
Wind-Adjusted Temperature	*12.5*

RCI Makeup



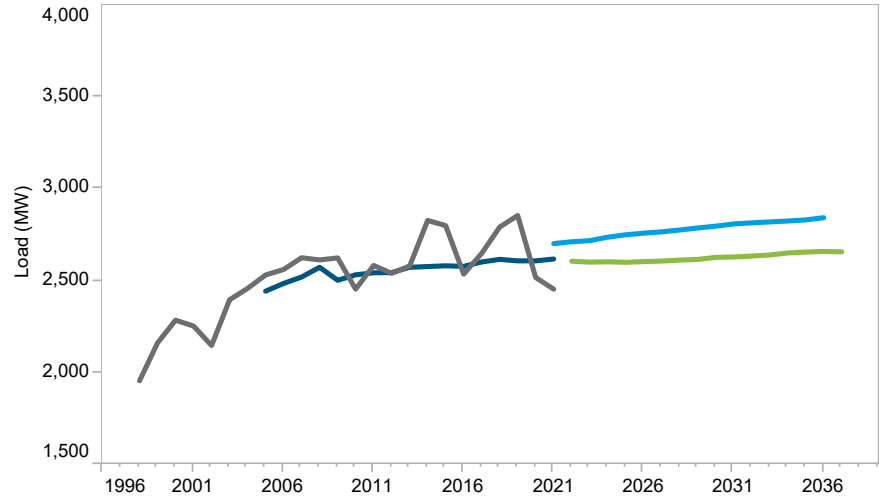
Zonal 10/15 Year Load Growth

SUMMER	0.4%	0.5%
WINTER	0.1%	0.1%

LDAs

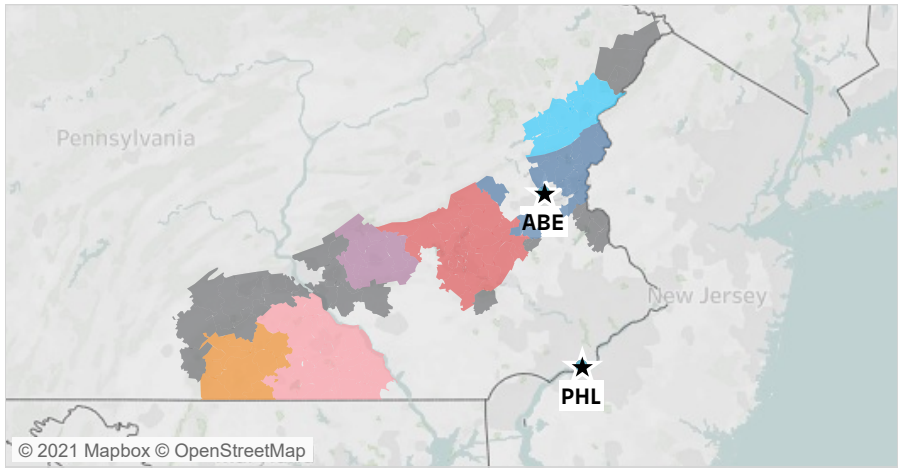
CENTRAL MID-ATLANTIC FE-EAST PJM MID-ATLANTIC
PJM RTO WESTERN MID-ATLANTIC

Winter Peak



Peak WN peak Forecast 2021 Forecast 2022

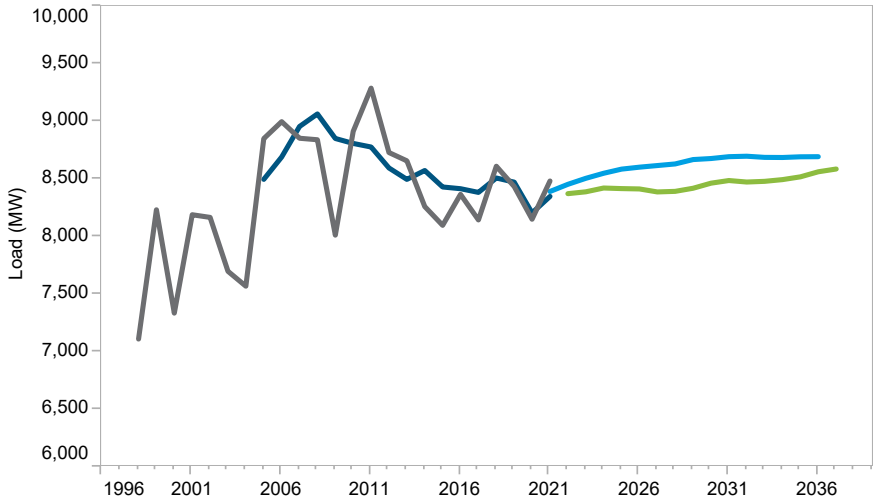
Metropolitan Statistical Areas and Weather Stations



- Allentown-Bethlehem-Easton, PA-NJ
- East Stroudsburg, PA
- Gettysburg, PA
- Lebanon, PA
- METED - Non-Metro
- Reading, PA
- York-Hanover, PA

PECO Energy (PECO)

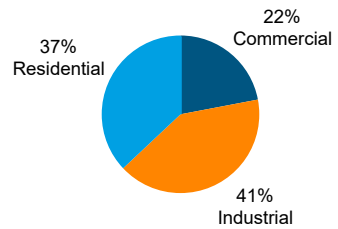
Summer Peak



Weather - Annual Average 1994-2020

Cooling Degree Days	*1,318*
Heating Degree Days	*3,352*
Temperature-Humidity Index	*84.9*
Wind-Adjusted Temperature	*14.2*

RCI Makeup



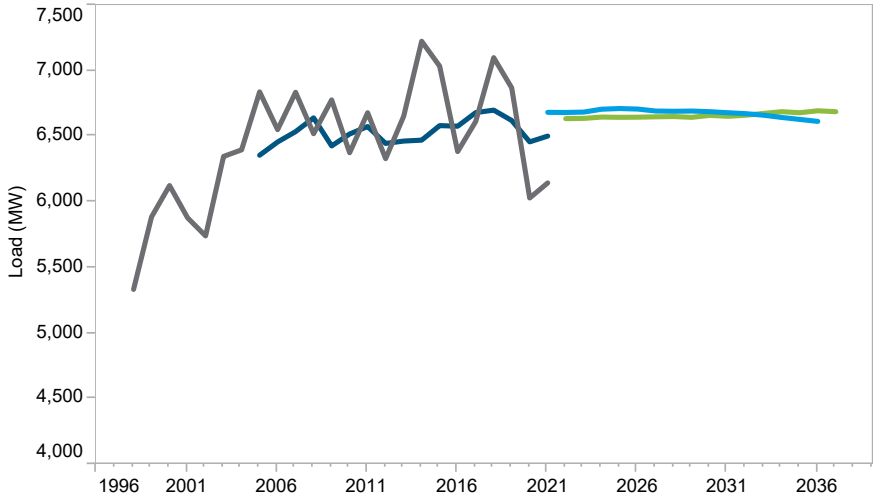
Zonal 10/15 Year Load Growth

SUMMER	0.1%	0.2%
WINTER	0.0%	0.1%

LDAs

EASTERN MID-ATLANTIC PJM MID-ATLANTIC PJM RTO

Winter Peak



Peak WN peak Forecast 2021 Forecast 2022

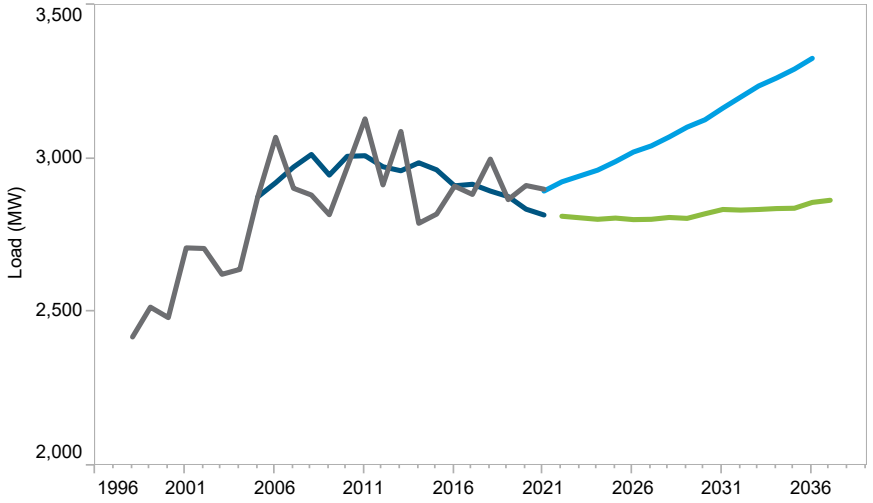
Metropolitan Statistical Areas and Weather Stations



Montgomery County-Bucks County-Chester County, PA
PECO - Non-Metro
Philadelphia, PA

Pennsylvania Electric Company (PENLC)

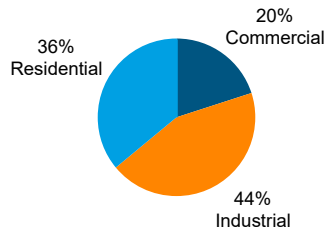
Summer Peak



Weather - Annual Average 1994-2020

Cooling Degree Days	*698*
Heating Degree Days	*4,636*
Temperature-Humidity Index	*81.7*
Wind-Adjusted Temperature	*8.1*

RCI Makeup



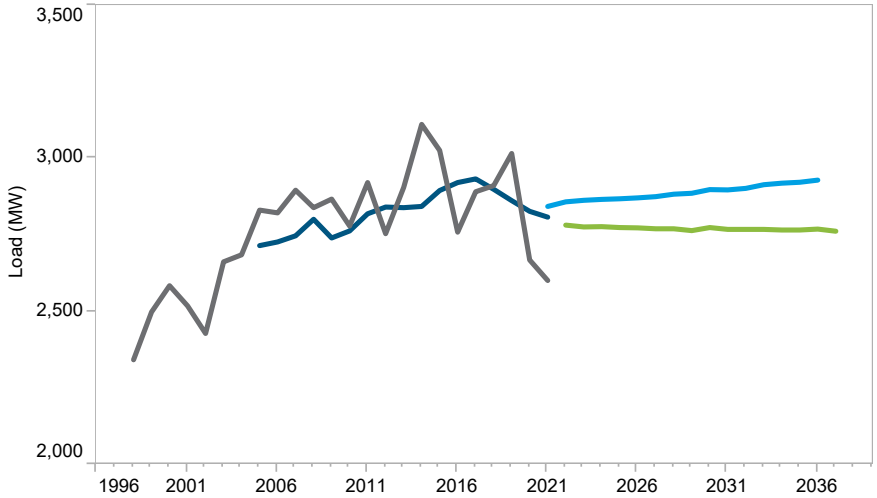
Zonal 10/15 Year Load Growth

SUMMER	0.1%	0.1%
WINTER	-0.1%	0.0%

LDAs

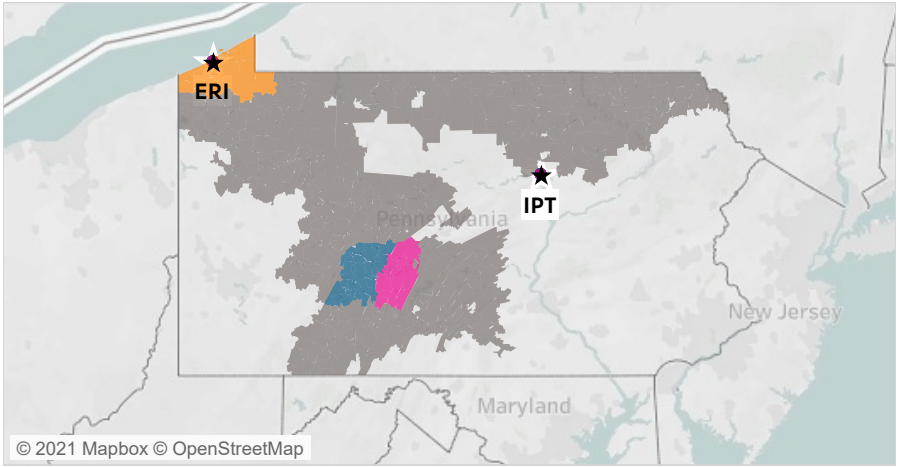
FE-EAST PJM MID-ATLANTIC PJM RTO
WESTERN MID-ATLANTIC

Winter Peak



Peak WN peak Forecast 2021 Forecast 2022

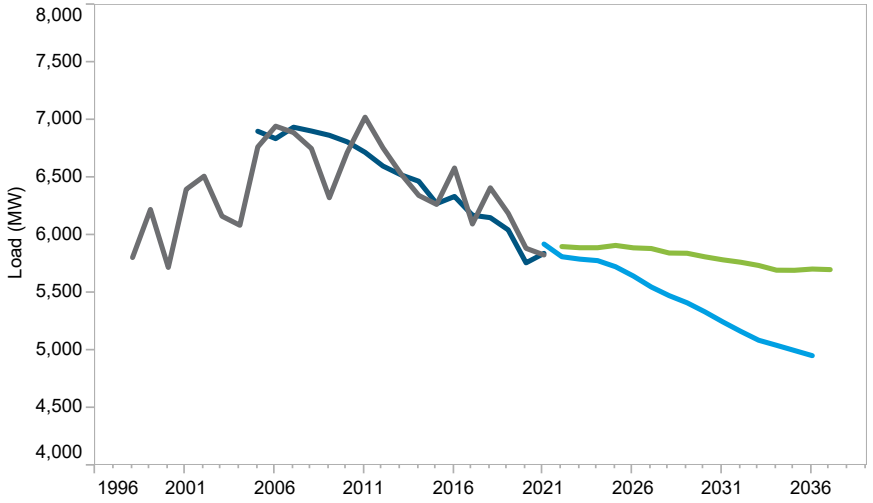
Metropolitan Statistical Areas and Weather Stations



Altoona, PA
Erie, PA
Johnstown, PA
PENLC - Non-Metro

Potomac Electric Power (PEPCO)

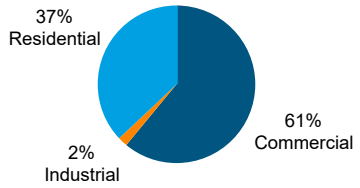
Summer Peak



Weather - Annual Average 1994-2020

Cooling Degree Days	*1,533*
Heating Degree Days	*2,900*
Temperature-Humidity Index	*85.3*
Wind-Adjusted Temperature	*17.7*

RCI Makeup



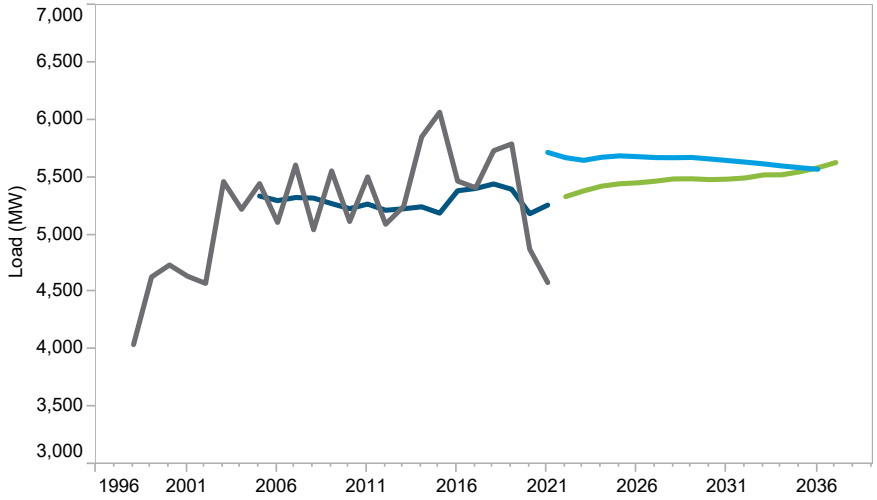
Zonal 10/15 Year Load Growth

SUMMER	-0.2%	-0.2%
WINTER	0.3%	0.4%

LDAs

CENTRAL MID-ATLANTIC PJM MID-ATLANTIC PJM RTO
SOUTHERN MID-ATLANTIC

Winter Peak



Peak WN peak Forecast 2021 Forecast 2022

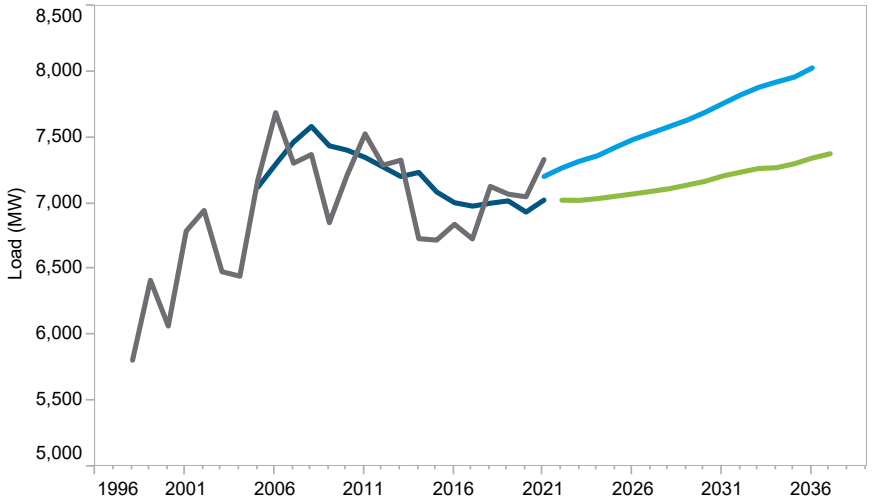
Metropolitan Statistical Areas and Weather Stations



California-Lexington Park, MD
PEPCO - Non-Metro
Washington-Arlington-Alexandria, DC-VA-MD-WV

PPL Electric Utilities (PL)

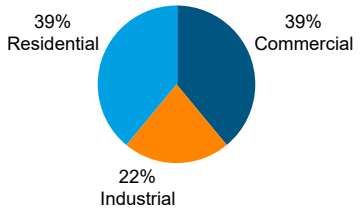
Summer Peak



Weather - Annual Average 1994-2020

Cooling Degree Days	*830*
Heating Degree Days	*4,333*
Temperature-Humidity Index	*82.9*
Wind-Adjusted Temperature	*9.8*

RCI Makeup



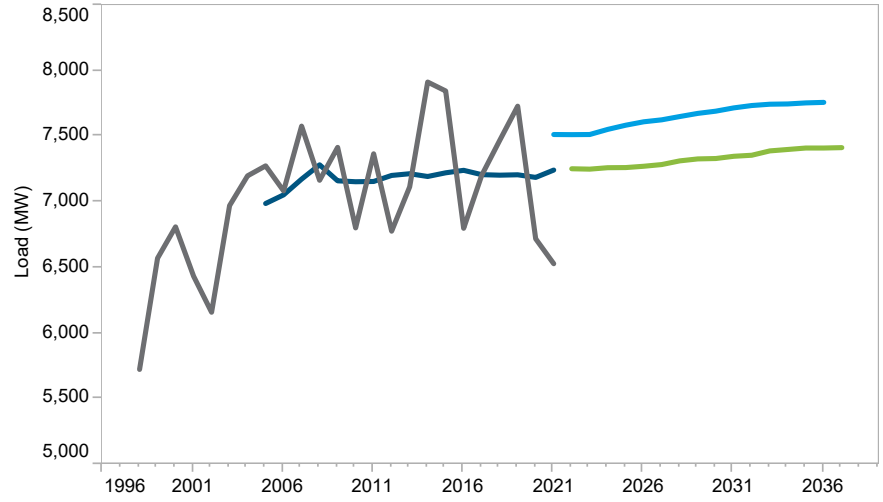
Zonal 10/15 Year Load Growth

SUMMER	0.3%	0.3%
WINTER	0.1%	0.1%

LDAs

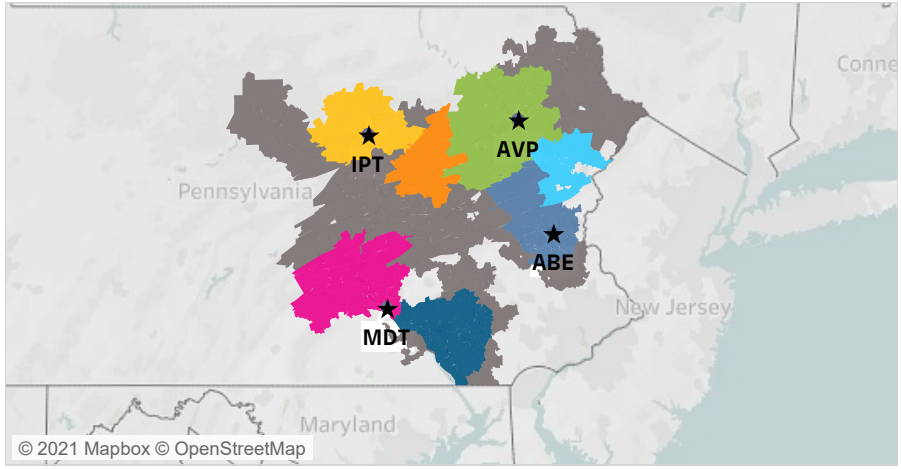
CENTRAL MID-ATLANTIC PJM MID-ATLANTIC PJM RTO
PLGRP WESTERN MID-ATLANTIC

Winter Peak



Peak WN peak Forecast 2021 Forecast 2022

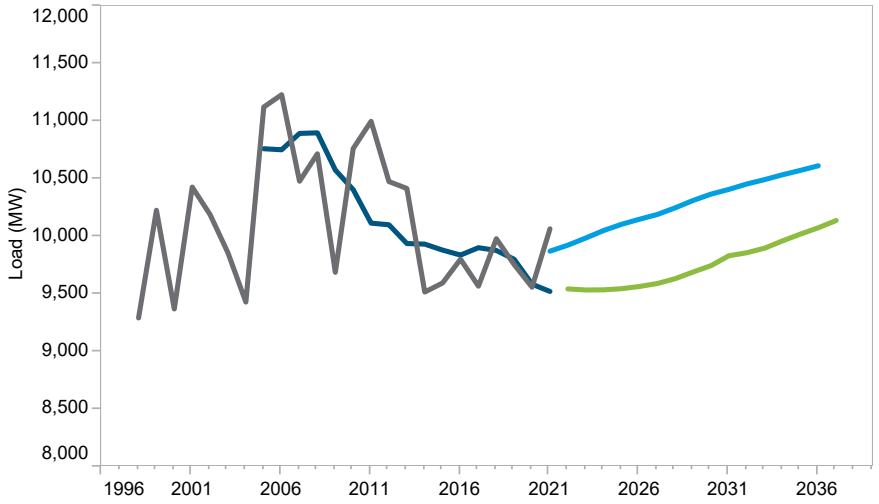
Metropolitan Statistical Areas and Weather Stations



Allentown-Bethlehem-Easton, PA-NJ
Bloomsburg-Berwick, PA
East Stroudsburg, PA
Harrisburg-Carlisle, PA
Lancaster, PA
PL - Non-Metro
Scranton--Wilkes-Barre--Hazleton, PA
Williamsport, PA

Public Service Electric & Gas (PS)

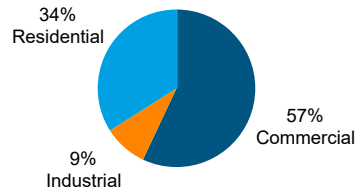
Summer Peak



Weather - Annual Average 1994-2020

Cooling Degree Days	*1,242*
Heating Degree Days	*3,549*
Temperature-Humidity Index	*84.7*
Wind-Adjusted Temperature	*11.1*

RCI Makeup



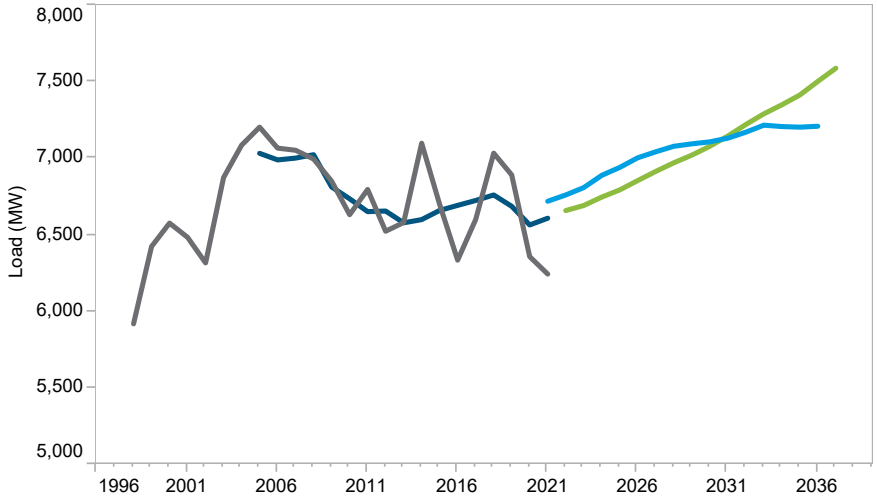
Zonal 10/15 Year Load Growth

SUMMER	0.3%	0.4%
WINTER	0.8%	0.9%

LDAs

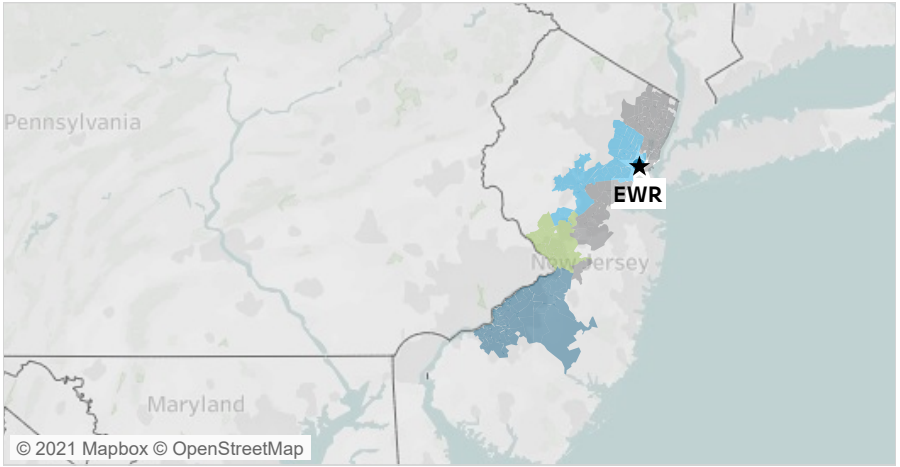
EASTERN MID-ATLANTIC PJM MID-ATLANTIC PJM RTO

Winter Peak



Peak WN peak Forecast 2021 Forecast 2022

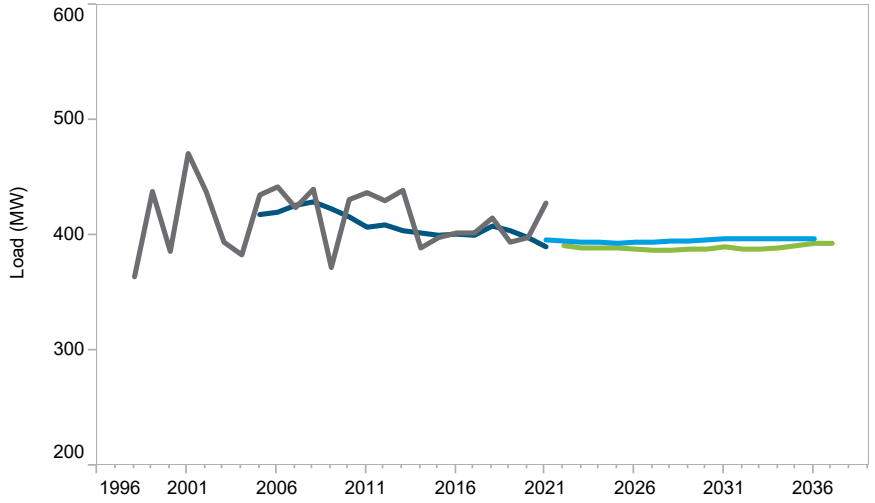
Metropolitan Statistical Areas and Weather Stations



Camden, NJ
Newark, NJ-PA
PS - Non-Metro
Trenton, NJ

Rockland Electric Company (RECO)

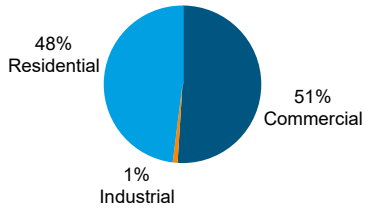
Summer Peak



Weather - Annual Average 1994-2020

Cooling Degree Days	*1,242*
Heating Degree Days	*3,549*
Temperature-Humidity Index	*84.7*
Wind-Adjusted Temperature	*11.1*

RCI Makeup



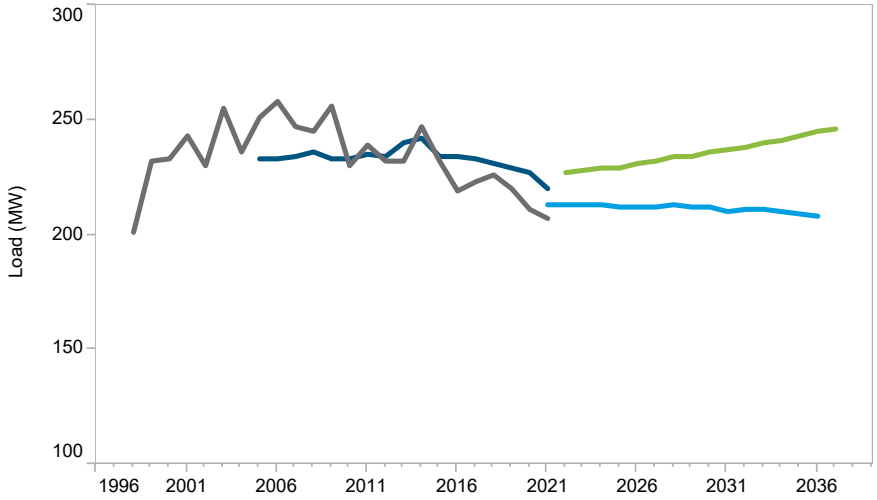
Zonal 10/15 Year Load Growth

SUMMER	-0.1%	0.0%
WINTER	0.5%	0.5%

LDAs

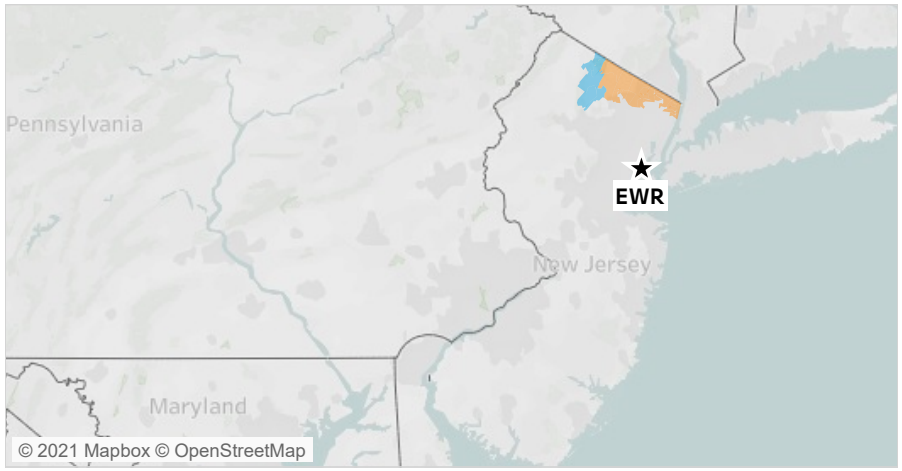
EASTERN MID-ATLANTIC PJM MID-ATLANTIC PJM RTO

Winter Peak



Peak WN peak Forecast 2021 Forecast 2022

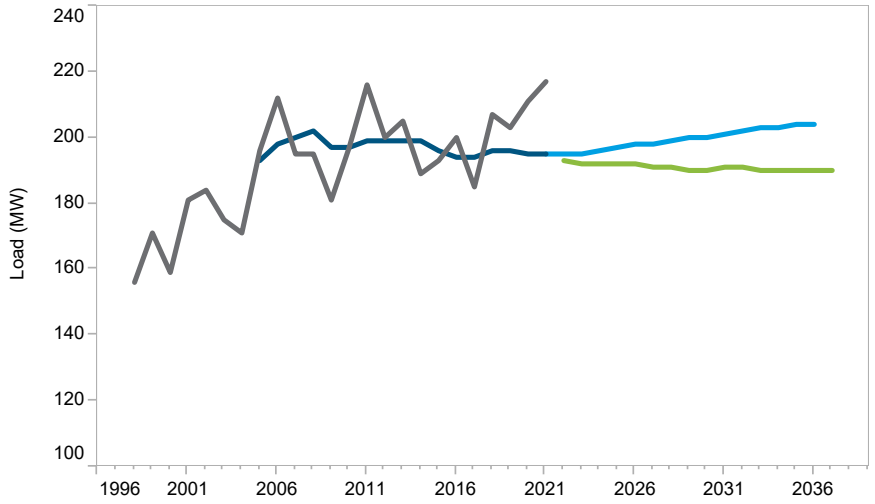
Metropolitan Statistical Areas and Weather Stations



New York-Jersey City-White Plains, NY-NJ
Newark, NJ-PA

UGI Energy Services (UGI)

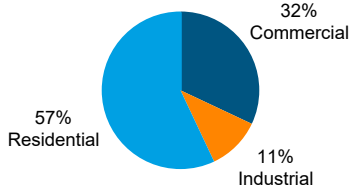
Summer Peak



Weather - Annual Average 1994-2020

Cooling Degree Days	*661*
Heating Degree Days	*4,689*
Temperature-Humidity Index	*82.2*
Wind-Adjusted Temperature	*6.4*

RCI Makeup



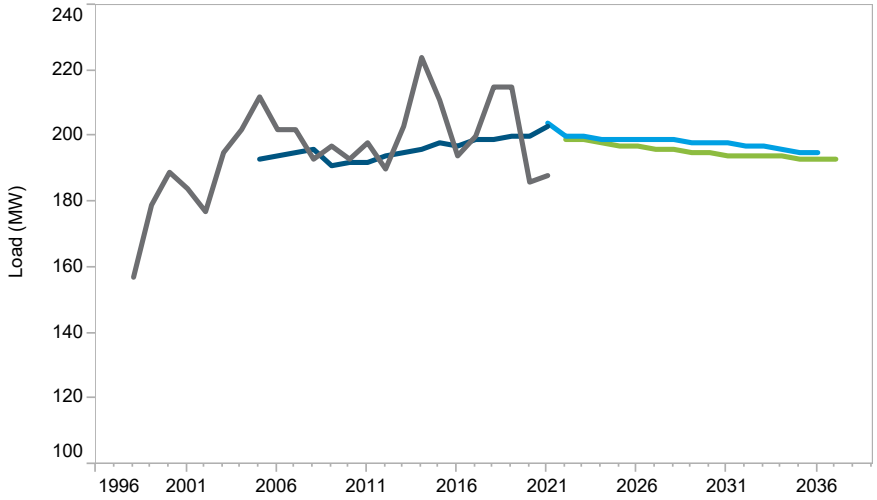
Zonal 10/15 Year Load Growth

SUMMER	-0.1%	-0.1%
WINTER	-0.3%	-0.2%

LDAs

CENTRAL MID-ATLANTIC PJM MID-ATLANTIC PJM RTO
PLGRP WESTERN MID-ATLANTIC

Winter Peak



Metropolitan Statistical Areas and Weather Stations

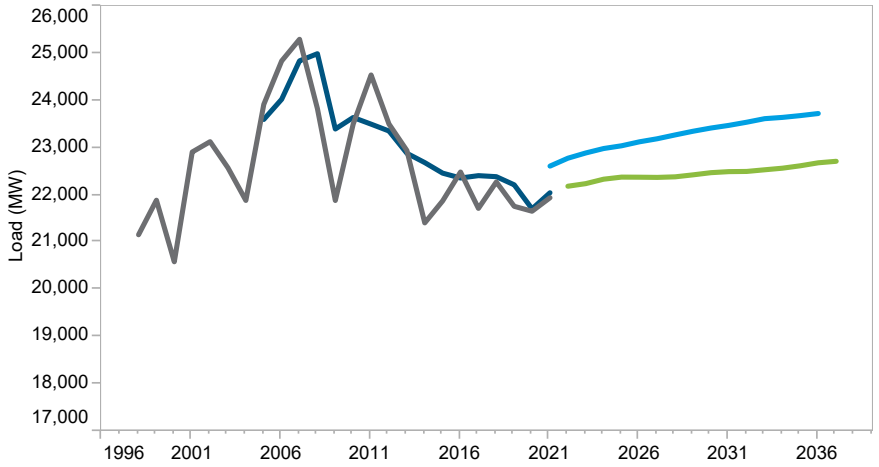


Scranton--Wilkes-Barre--Hazleton, PA

Peak WN peak Forecast 2021 Forecast 2022

American Electric Power (AEP)

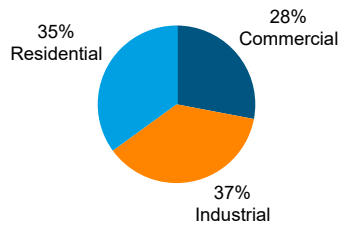
Summer Peak



Weather - Annual Average 1994-2020

Cooling Degree Days	*927*
Heating Degree Days	*3,939*
Temperature-Humidity Index	*82.2*
Wind-Adjusted Temperature	*9.2*

RCI Makeup



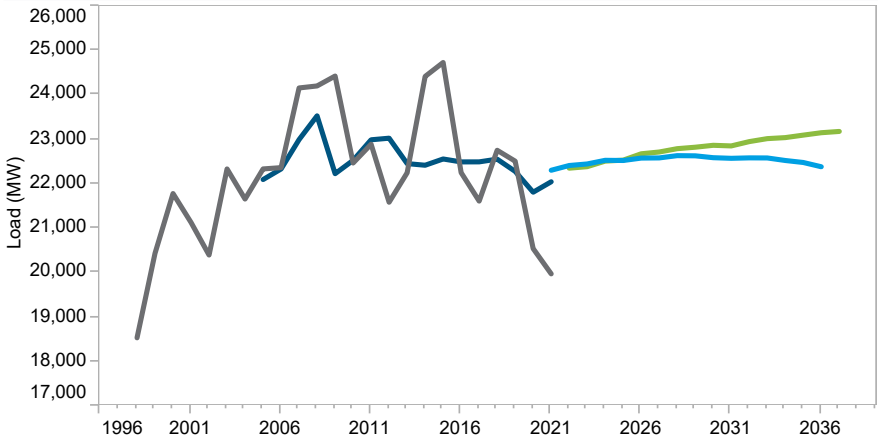
Zonal 10/15 Year Load Growth

SUMMER	0.1%	0.2%
WINTER	0.3%	0.2%

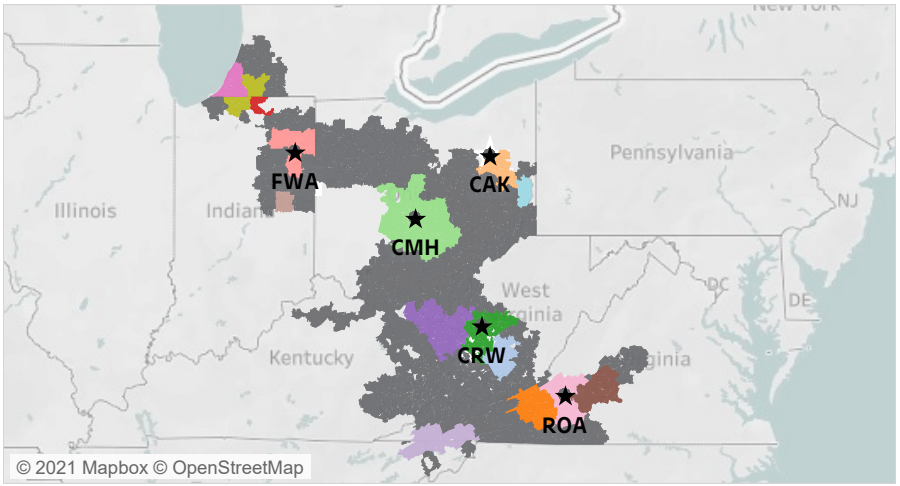
LDAs

PJM RTO PJM WESTERN

Winter Peak



Metropolitan Statistical Areas and Weather Stations

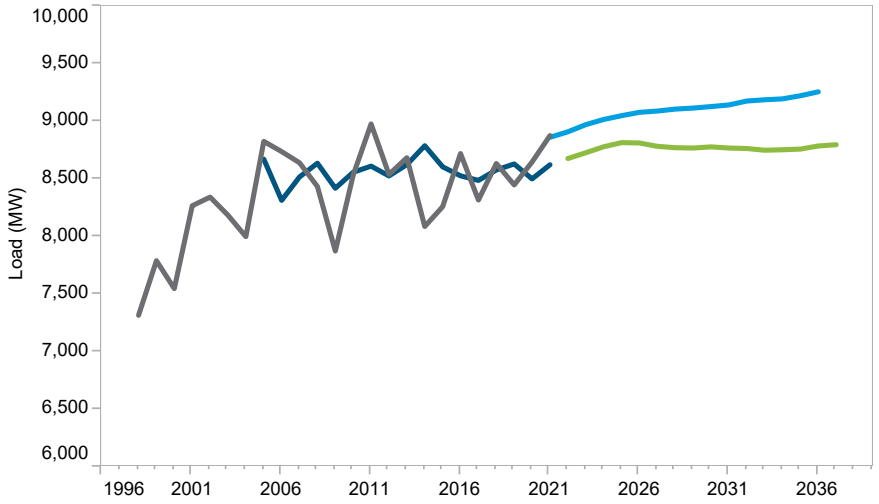


Peak
WN peak
Forecast 2021
Forecast 2022

AEP - Non-Metro
Beckley, WV
Blacksburg-Christiansburg-Radford, VA
Canton-Massillon, OH
Charleston, WV
Columbus, OH
Elkhart-Goshen, IN
Fort Wayne, IN
Huntington-Ashland, WV-KY-OH
Kingsport-Bristol-Bristol, TN-VA
Lynchburg, VA
Muncie, IN
Niles-Benton Harbor, MI
Roanoke, VA
South Bend-Mishawaka, IN-MI
Weirton-Steubenville, WV-OH

Allegheny Power Systems (APS)

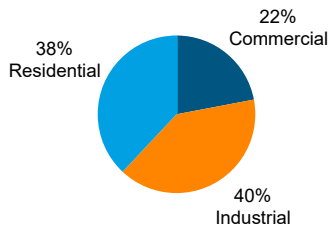
Summer Peak



Weather - Annual Average 1994-2020

Cooling Degree Days	*889*
Heating Degree Days	*4,054*
Temperature-Humidity Index	*82.2*
Wind-Adjusted Temperature	*8.8*

RCI Makeup



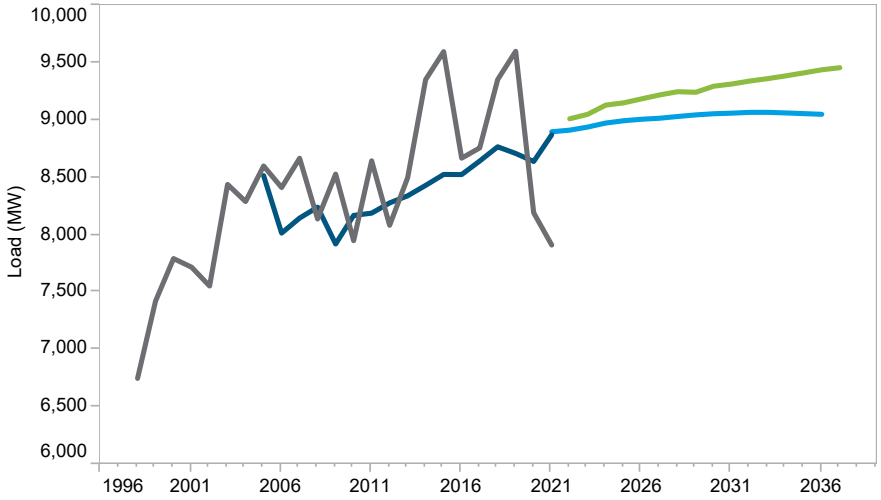
Zonal 10/15 Year Load Growth

SUMMER	0.1%	0.1%
WINTER	0.4%	0.3%

LDAs

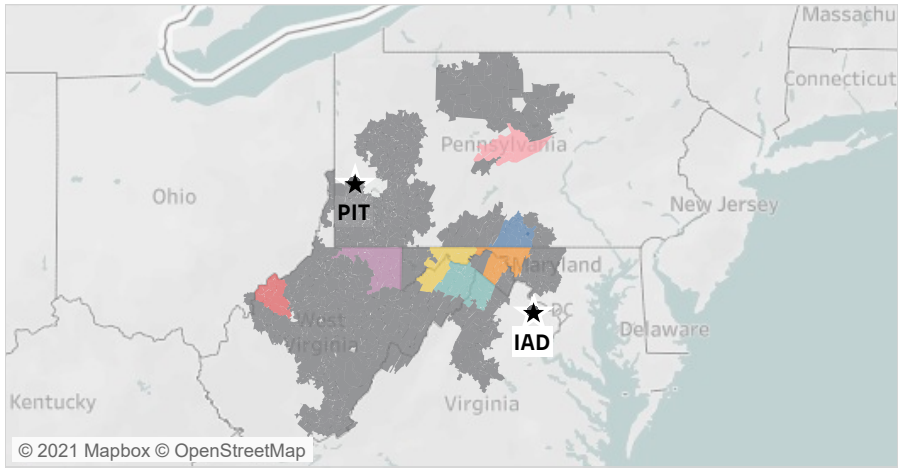
PJM RTO PJM WESTERN

Winter Peak



Peak WN peak Forecast 2021 Forecast 2022

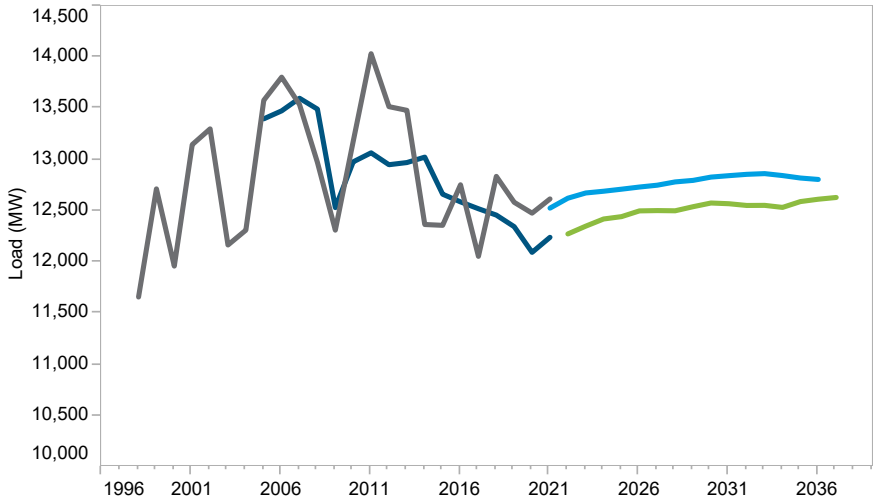
Metropolitan Statistical Areas and Weather Stations



APS - Non-metro
Chambersburg-Waynesboro, PA
Cumberland, MD-WV
Hagerstown-Martinsburg, MD-WV
Morgantown, WV
Parkersburg-Vienna, WV
State College, PA
Winchester, VA-WV

American Transmission Systems, Inc. (ATSI)

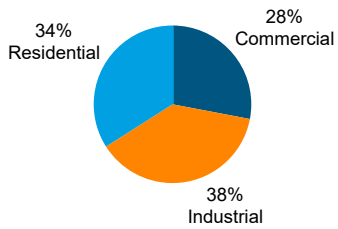
Summer Peak



Weather - Annual Average 1994-2020

Cooling Degree Days	*774*
Heating Degree Days	*4,636*
Temperature-Humidity Index	*81.9*
Wind-Adjusted Temperature	*4.3*

RCI Makeup



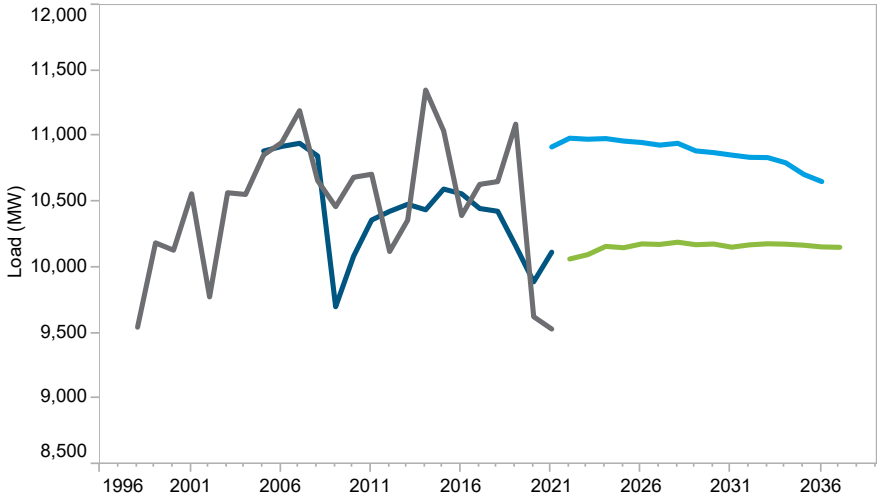
Zonal 10/15 Year Load Growth

SUMMER	0.2%	0.2%
WINTER	0.1%	0.1%

LDAs

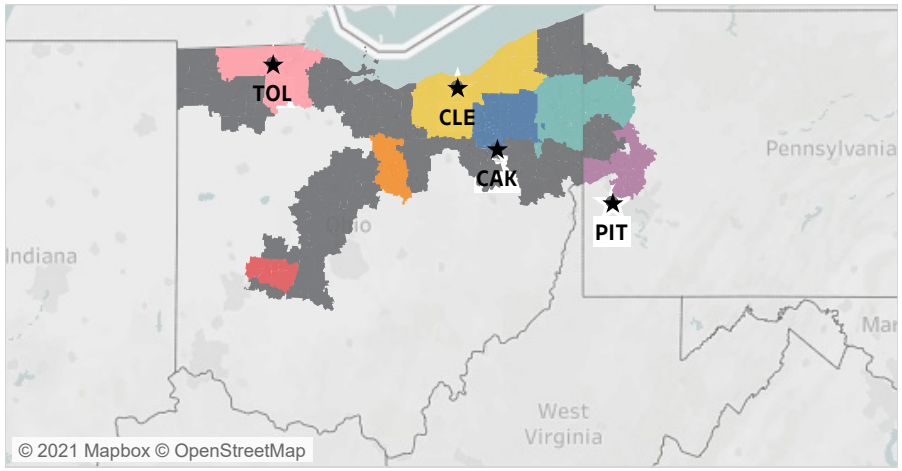
PJM RTO PJM WESTERN

Winter Peak



Peak WN peak Forecast 2021 Forecast 2022

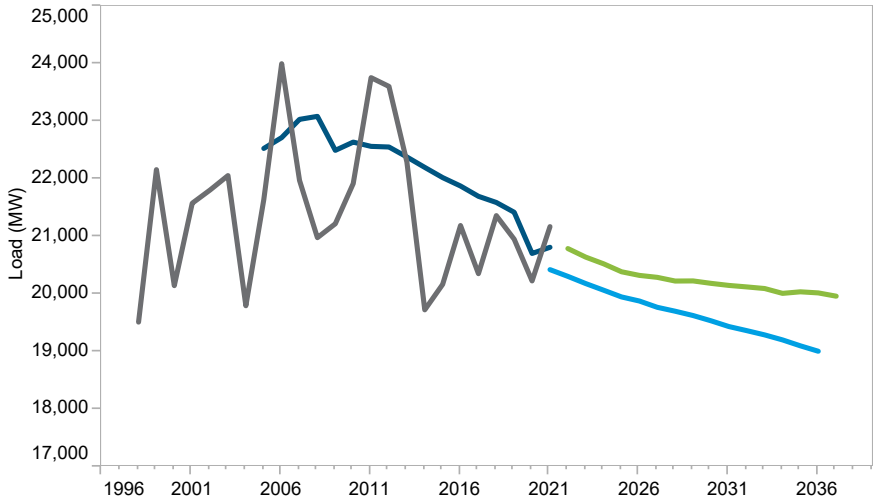
Metropolitan Statistical Areas and Weather Stations



Akron, OH
ATSI - Non-Metro
Cleveland-Elyria, OH
Mansfield, OH
Pittsburgh, PA
Springfield, OH
Toledo, OH
Youngstown-Warren-Boardman, OH-PA

Commonweath Edison (COMED)

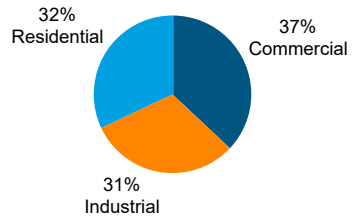
Summer Peak



Weather - Annual Average 1994-2020

Cooling Degree Days	*927*
Heating Degree Days	*4,920*
Temperature-Humidity Index	*84.0*
Wind-Adjusted Temperature	*-1.2*

RCI Makeup



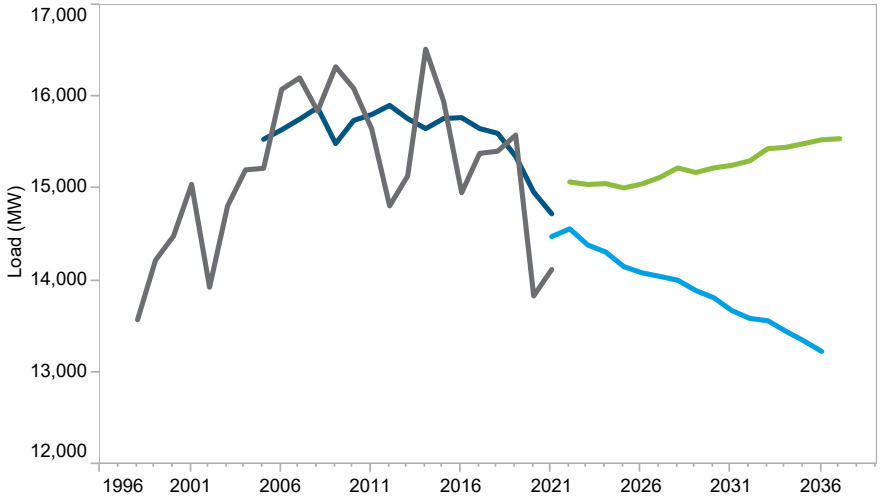
Zonal 10/15 Year Load Growth

SUMMER	-0.3%	-0.3%
WINTER	0.2%	0.2%

LDAs

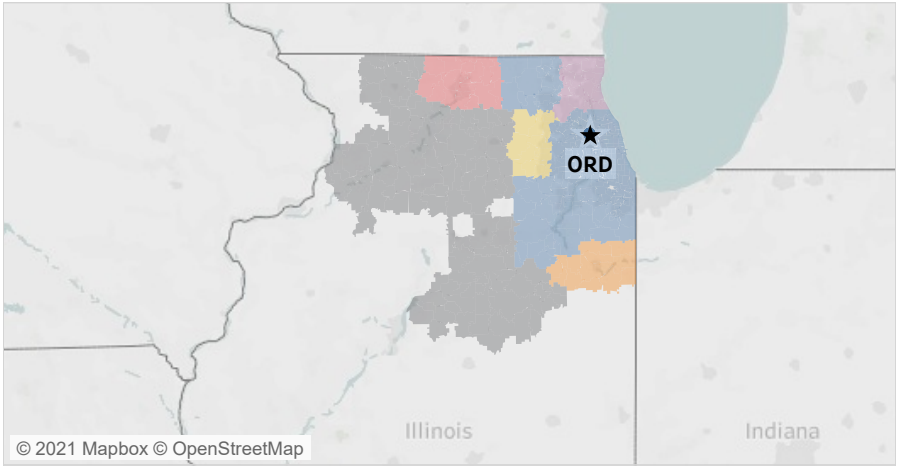
PJM RTO PJM WESTERN

Winter Peak



Peak WN peak Forecast 2021 Forecast 2022

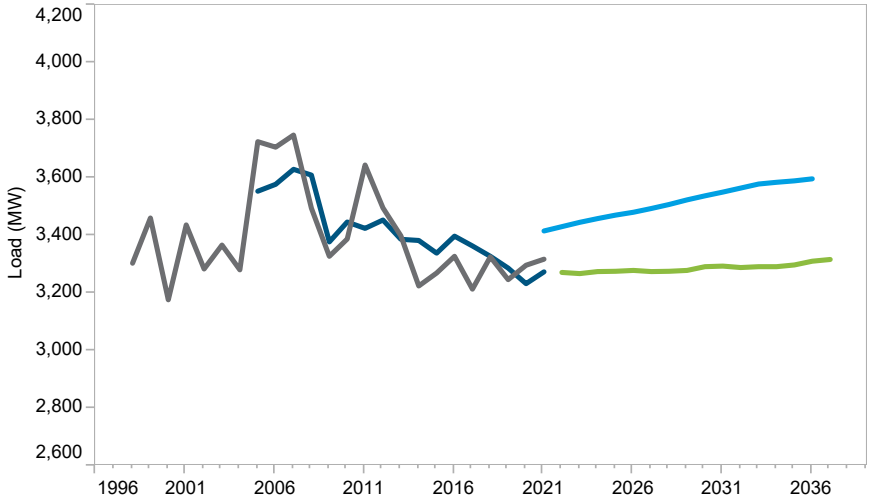
Metropolitan Statistical Areas and Weather Stations



Chicago-Naperville-Arlington Heights, IL
Chicago-Naperville-Elgin, IL-IN-WI
COMED - Non-Metro
Kankakee, IL
Lake County-Kenosha County, IL-WI
Rockford, IL

Dayton Power and Light (DAYTON)

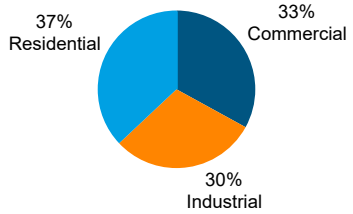
Summer Peak



Weather - Annual Average 1994-2020

Cooling Degree Days	*951*
Heating Degree Days	*4,308*
Temperature-Humidity Index	*83.1*
Wind-Adjusted Temperature	*3.4*

RCI Makeup



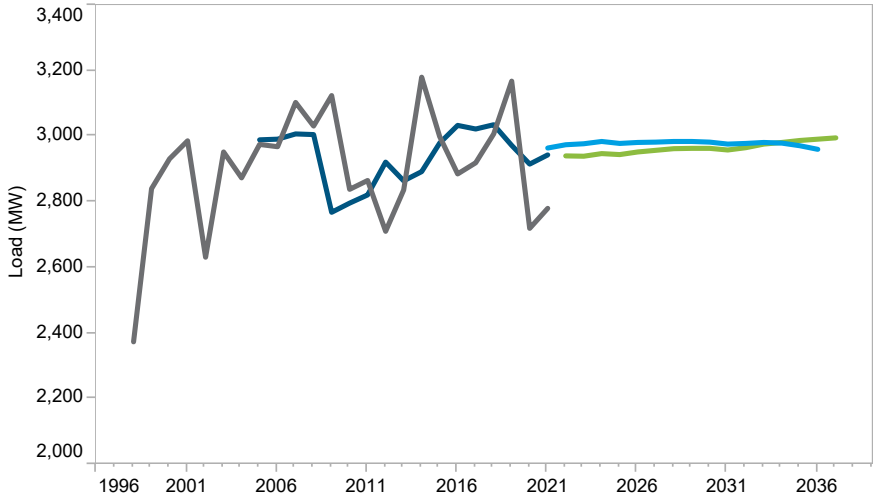
Zonal 10/15 Year Load Growth

SUMMER	0.1%	0.1%
WINTER	0.1%	0.1%

LDAs

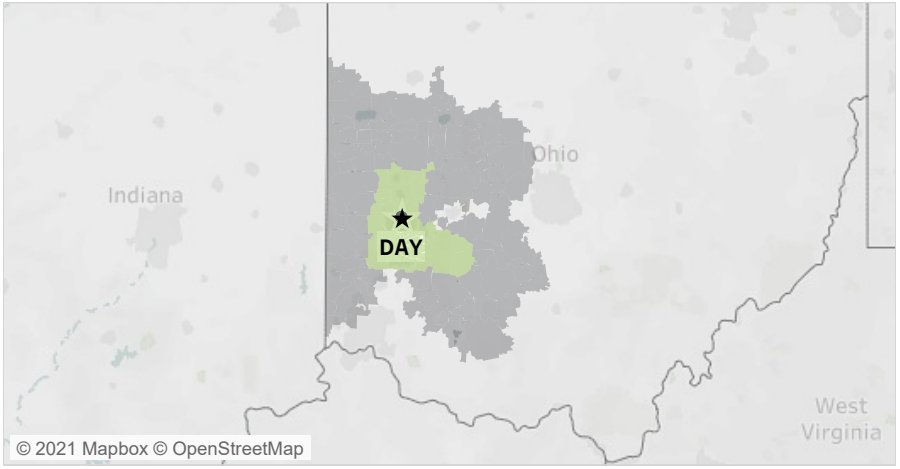
PJM RTO PJM WESTERN

Winter Peak



Peak WN peak Forecast 2021 Forecast 2022

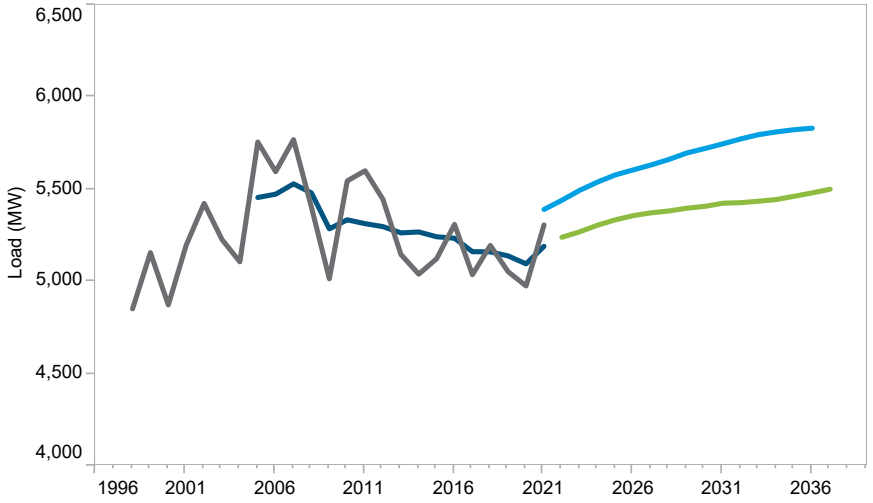
Metropolitan Statistical Areas and Weather Stations



DAY - Non-Metro
Dayton, OH

Duke Energy Ohio and Kentucky (DEOK)

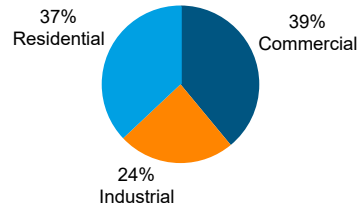
Summer Peak



Weather - Annual Average 1994-2020

Cooling Degree Days	*1,099*
Heating Degree Days	*3,792*
Temperature-Humidity Index	*83.8*
Wind-Adjusted Temperature	*8.2*

RCI Makeup



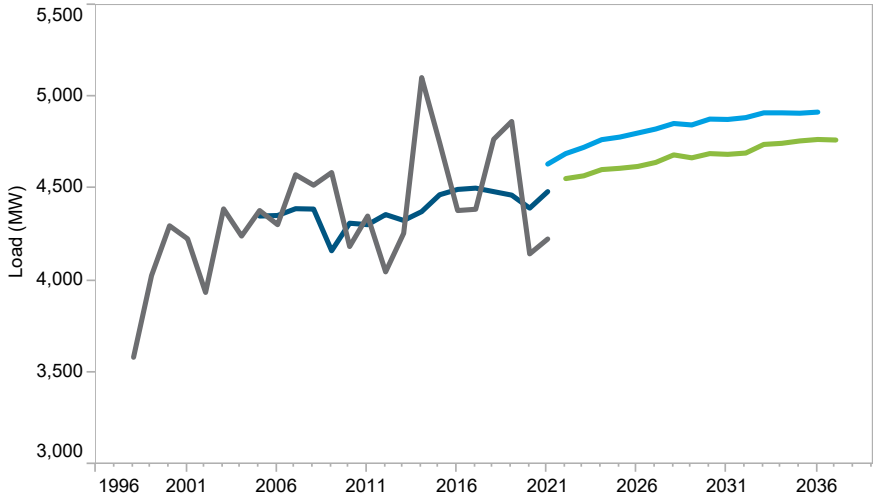
Zonal 10/15 Year Load Growth

SUMMER	0.4%	0.3%
WINTER	0.3%	0.3%

LDAs

PJM RTO PJM WESTERN

Winter Peak



Peak WN peak Forecast 2021 Forecast 2022

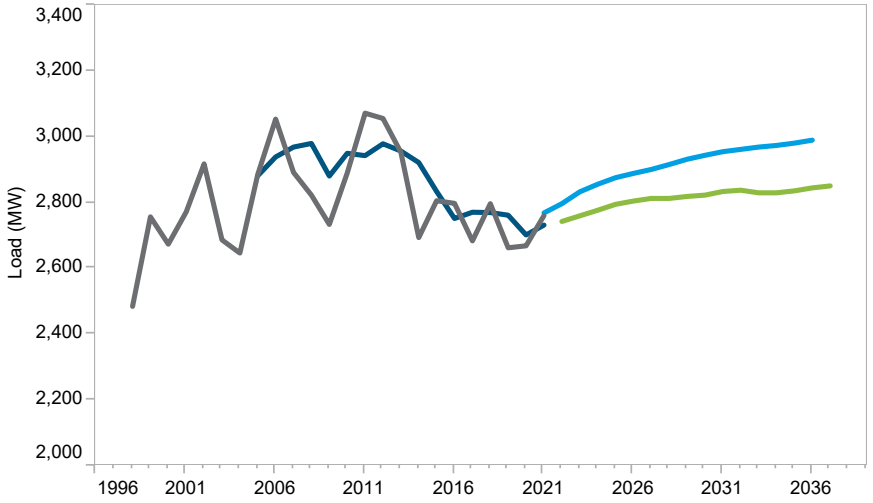
Metropolitan Statistical Areas and Weather Stations



Cincinnati, OH-KY-IN
DEOK - Non-Metro

Duquesne Light Company (DLCO)

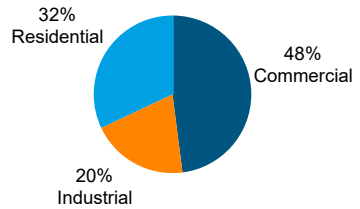
Summer Peak



Weather - Annual Average 1994-2020

Cooling Degree Days	*787*
Heating Degree Days	*4,347*
Temperature-Humidity Index	*81.9*
Wind-Adjusted Temperature	*5.4*

RCI Makeup



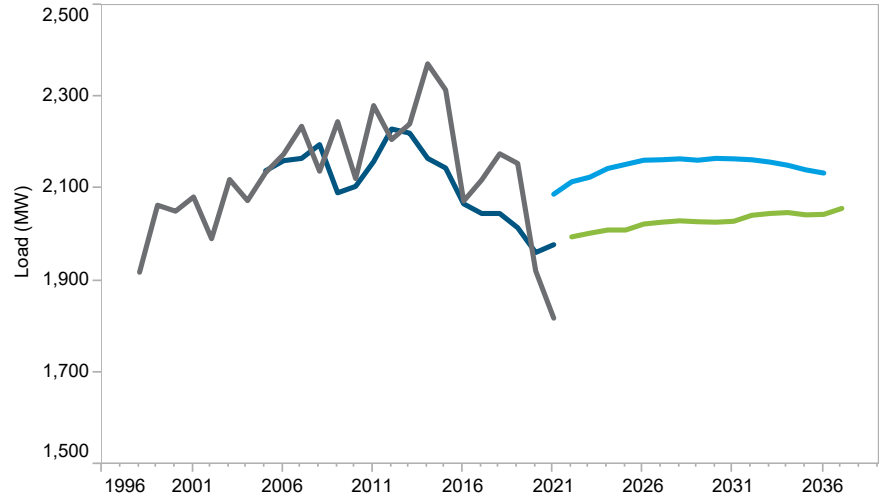
Zonal 10/15 Year Load Growth

SUMMER	0.3%	0.3%
WINTER	0.2%	0.2%

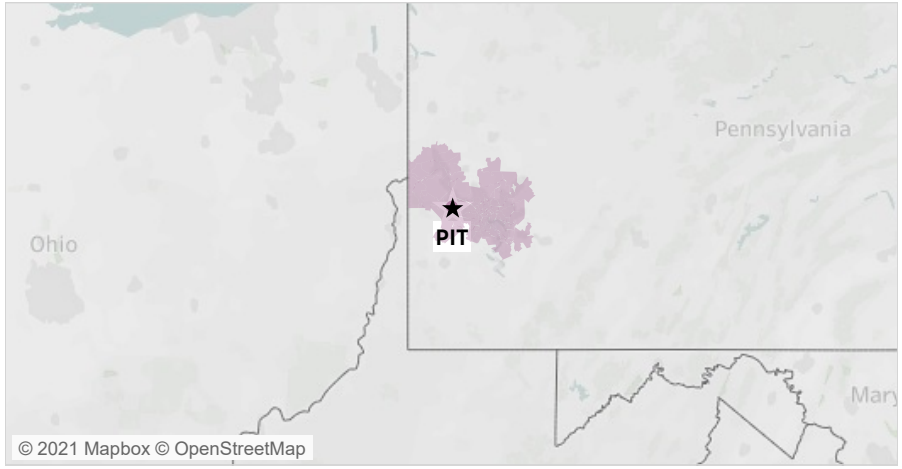
LDAs

PJM RTO PJM WESTERN

Winter Peak



Metropolitan Statistical Areas and Weather Stations

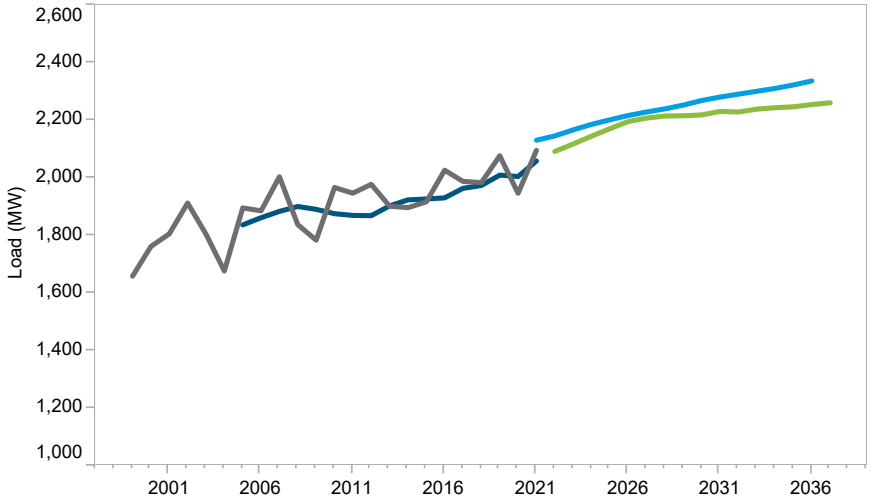


Pittsburgh, PA

Peak WN peak Forecast 2021 Forecast 2022

East Kentucky Power Cooperative (EKPC)

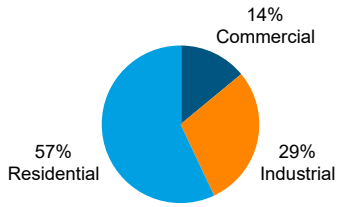
Summer Peak



Weather - Annual Average 1994-2020

Cooling Degree Days	*1,243*
Heating Degree Days	*3,433*
Temperature-Humidity Index	*83.9*
Wind-Adjusted Temperature	*11.0*

RCI Makeup



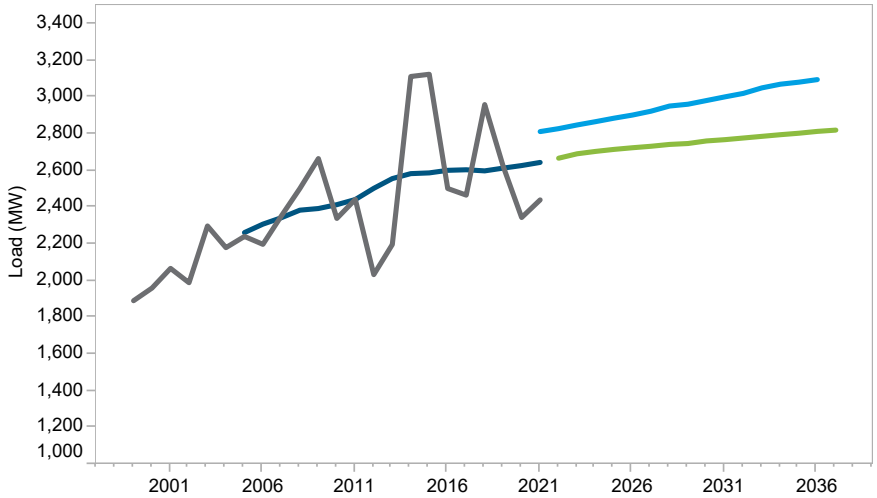
Zonal 10/15 Year Load Growth

SUMMER	0.6%	0.5%
WINTER	0.4%	0.4%

LDAs

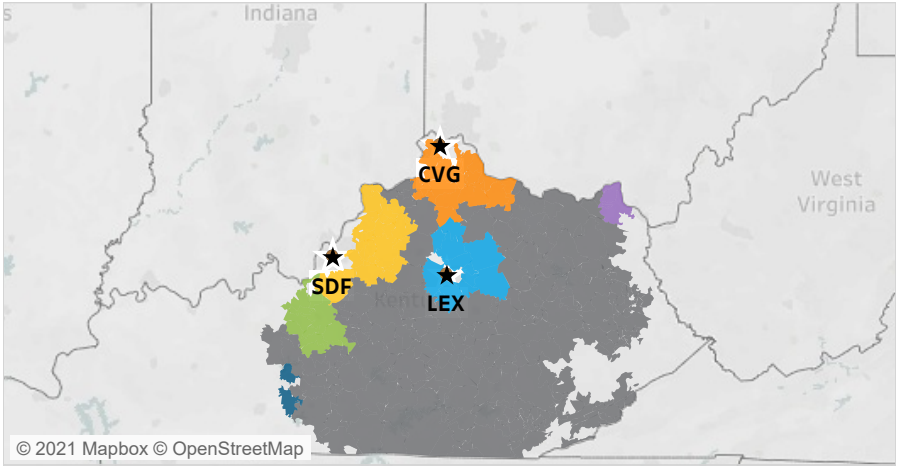
PJM RTO PJM WESTERN

Winter Peak



Peak WN peak Forecast 2021 Forecast 2022

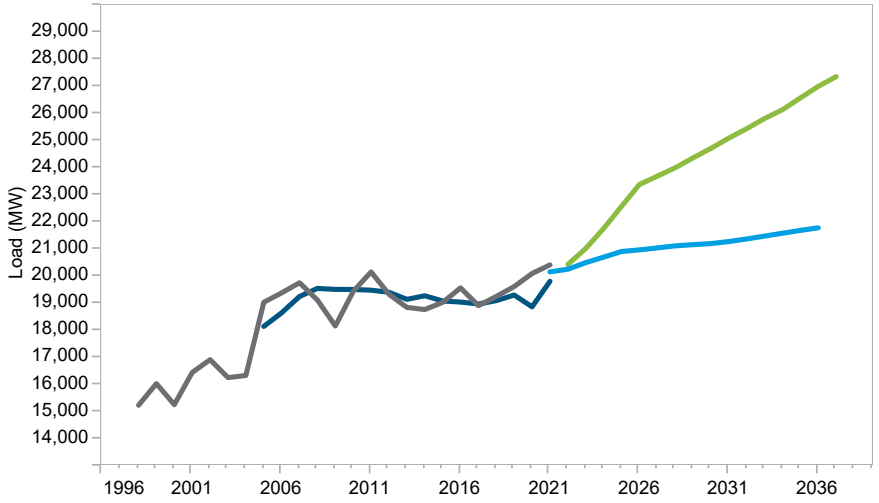
Metropolitan Statistical Areas and Weather Stations



- Bowling Green, KY
- Cincinnati, OH-KY-IN
- EKPC - Non-Metro
- Elizabethtown-Fort Knox, KY
- Huntington-Ashland, WV-KY-OH
- Lexington-Fayette, KY
- Louisville/Jefferson County, KY-IN

Dominion (DOM)

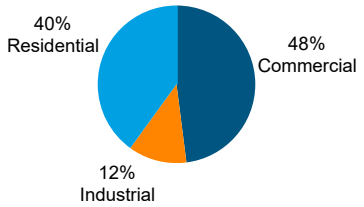
Summer Peak



Weather - Annual Average 1994-2020

Cooling Degree Days	*1,403*
Heating Degree Days	*2,749*
Temperature-Humidity Index	*84.7*
Wind-Adjusted Temperature	*20.5*

RCI Makeup



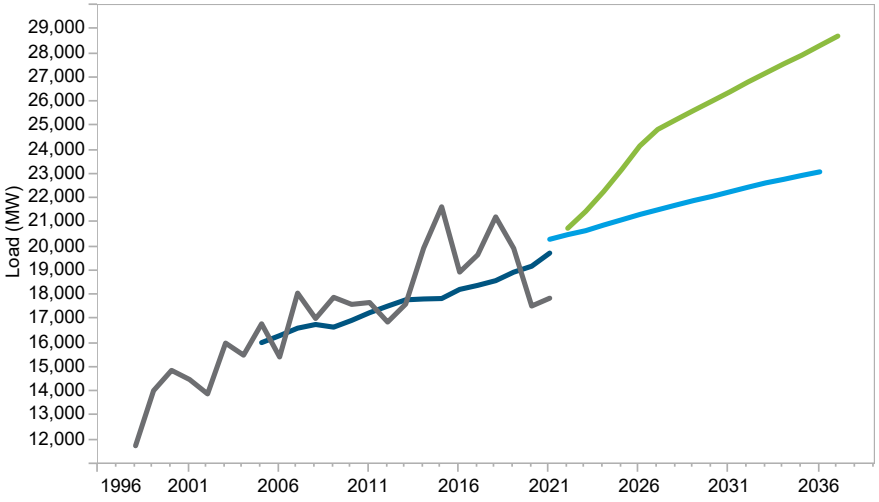
Zonal 10/15 Year Load Growth

SUMMER	2.2%	2.0%
WINTER	2.6%	2.2%

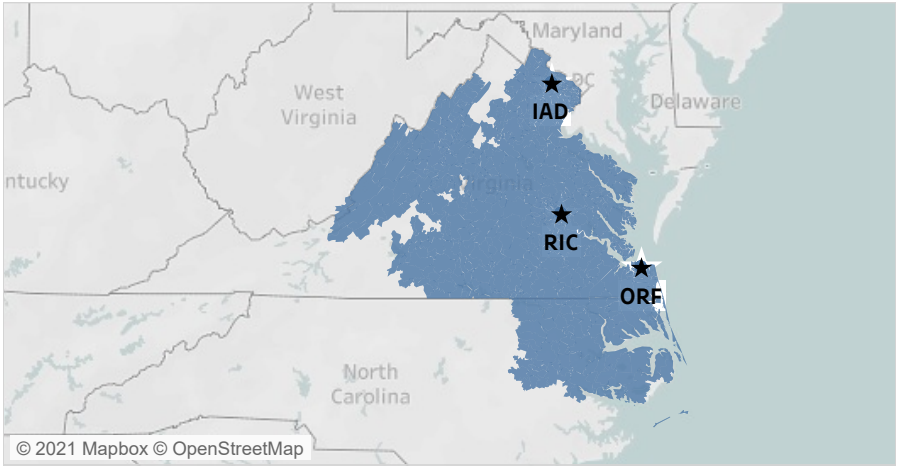
LDAs

PJM RTO

Winter Peak



Metropolitan Statistical Areas and Weather Stations



Virginia Commonwealth Economics

Peak WN peak Forecast 2021 Forecast 2022

Table A-1

PJM MID-ATLANTIC REGION
SUMMER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST
TO THE JANUARY 2021 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	2022		2027		2032	
	MW	**%**	**MW**	**%**	**MW**	**%**
AE	(4)	-0.2%	(57)	-2.2%	(81)	-3.1%
BGE	(192)	-2.9%	(282)	-4.2%	(285)	-4.3%
DPL	(33)	-0.8%	(62)	-1.6%	(97)	-2.5%
JCPL	(60)	-1.0%	(289)	-4.8%	(371)	-5.9%
METED	(151)	-4.9%	(204)	-6.4%	(214)	-6.5%
PECO	(81)	-1.0%	(229)	-2.7%	(224)	-2.6%
PENLC	(112)	-3.8%	(239)	-7.9%	(368)	-11.5%
PEPCO	88	1.5%	334	6.0%	600	11.6%
PL	(245)	-3.4%	(443)	-5.9%	(587)	-7.5%
PS	(380)	-3.8%	(599)	-5.9%	(597)	-5.7%
RECO	(4)	-1.0%	(7)	-1.8%	(9)	-2.3%
UGI	(2)	-1.0%	(7)	-3.5%	(11)	-5.4%
PJM MID-ATLANTIC	(893)	-1.6%	(2,156)	-3.8%	(2,238)	-3.9%
FE-EAST	(418)	-3.6%	(830)	-6.9%	(1,031)	-8.2%
PLGRP	(258)	-3.5%	(467)	-6.0%	(606)	-7.6%

Table A-1

PJM WESTERN REGION, PJM SOUTHERN REGION AND PJM RTO
SUMMER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST
TO THE JANUARY 2021 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	2022		2027		2032	
	MW	**%**	**MW**	**%**	**MW**	**%**
AEP	(593)	-2.6%	(818)	-3.5%	(1,042)	-4.4%
APS	(232)	-2.6%	(306)	-3.4%	(412)	-4.5%
ATSI	(349)	-2.8%	(248)	-1.9%	(304)	-2.4%
COMED	483	2.4%	520	2.6%	759	3.9%
DAYTON	(159)	-4.6%	(219)	-6.3%	(276)	-7.7%
DEOK	(201)	-3.7%	(260)	-4.6%	(346)	-6.0%
DLCO	(54)	-1.9%	(88)	-3.0%	(124)	-4.2%
EKPC	(54)	-2.5%	(21)	-0.9%	(62)	-2.7%
OVEC	0	0.0%	0	0.0%	0	0.0%
PJM WESTERN	(590)	-0.8%	(851)	-1.1%	(1,278)	-1.7%
DOM	176	0.9%	2,647	12.6%	4,069	19.0%
PJM RTO	(1,028)	-0.7%	(249)	-0.2%	336	0.2%

Table A-2

PJM MID-ATLANTIC REGION
WINTER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST
TO THE JANUARY 2021 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	21/22		26/27		31/32	
	MW	**%**	**MW**	**%**	**MW**	**%**
AE	69	4.5%	72	4.5%	98	6.1%
BGE	(276)	-4.6%	(269)	-4.3%	(230)	-3.6%
DPL	(295)	-7.6%	(302)	-7.5%	(309)	-7.4%
JCPL	17	0.5%	(47)	-1.2%	(24)	-0.6%
METED	(106)	-3.9%	(159)	-5.8%	(181)	-6.4%
PECO	(47)	-0.7%	(44)	-0.7%	(12)	-0.2%
PENLC	(76)	-2.7%	(105)	-3.7%	(134)	-4.6%
PEPCO	(339)	-6.0%	(205)	-3.6%	(137)	-2.4%
PL	(260)	-3.5%	(341)	-4.5%	(379)	-4.9%
PS	(102)	-1.5%	(128)	-1.8%	50	0.7%
RECO	14	6.6%	20	9.4%	27	12.8%
UGI	(1)	-0.5%	(3)	-1.5%	(3)	-1.5%
PJM MID-ATLANTIC	(726)	-1.6%	(963)	-2.0%	(722)	-1.5%
FE-EAST	(108)	-1.2%	(240)	-2.6%	(297)	-3.1%
PLGRP	(257)	-3.3%	(339)	-4.3%	(380)	-4.8%

Table A-2

PJM WESTERN REGION, PJM SOUTHERN REGION AND PJM RTO
WINTER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST
TO THE JANUARY 2021 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	21/22		26/27		31/32	
	MW	**%**	**MW**	**%**	**MW**	**%**
AEP	(60)	-0.3%	133	0.6%	366	1.6%
APS	99	1.1%	203	2.3%	273	3.0%
ATSI	(921)	-8.4%	(757)	-6.9%	(667)	-6.2%
COMED	510	3.5%	1,077	7.7%	1,716	12.6%
DAYTON	(34)	-1.1%	(25)	-0.8%	(13)	-0.4%
DEOK	(136)	-2.9%	(182)	-3.8%	(193)	-3.9%
DLCO	(120)	-5.7%	(136)	-6.3%	(121)	-5.6%
EKPC	(161)	-5.7%	(191)	-6.5%	(243)	-8.0%
OVEC	(5)	-4.2%	(5)	-4.2%	(5)	-4.2%
PJM WESTERN	(639)	-0.9%	238	0.3%	1,094	1.6%
DOM	263	1.3%	3,327	15.5%	4,351	19.4%
PJM RTO	(530)	-0.4%	3,144	2.3%	5,717	4.2%

Table B-1

SUMMER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION 2022 - 2032

	METERED 2021	UNRESTRICTED 2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Annual Growth Rate (10 yr)
AE	2,631	2,631	2,488	2,490	2,493	2,479	2,478	2,484	2,503	2,511	2,527	2,528	2,541	0.2%
				0.1%	0.1%	-0.6%	-0.0%	0.2%	0.8%	0.3%	0.6%	0.0%	0.5%	
BGE	6,486	6,486	6,414	6,391	6,389	6,390	6,401	6,398	6,391	6,404	6,399	6,384	6,350	(0.1%)
				-0.4%	-0.0%	0.0%	0.2%	-0.0%	-0.1%	0.2%	-0.1%	-0.2%	-0.5%	
DPL	4,007	4,007	3,873	3,882	3,893	3,899	3,902	3,907	3,917	3,924	3,922	3,893	3,854	(0.0%)
				0.2%	0.3%	0.2%	0.1%	0.1%	0.3%	0.2%	-0.1%	-0.7%	-1.0%	
JCPL	6,170	6,170	5,831	5,799	5,771	5,772	5,771	5,748	5,762	5,789	5,810	5,847	5,868	0.1%
				-0.5%	-0.5%	0.0%	-0.0%	-0.4%	0.2%	0.5%	0.4%	0.6%	0.4%	
METED	3,072	3,072	2,934	2,934	2,942	2,950	2,966	2,979	2,988	3,003	3,024	3,042	3,060	0.4%
				0.0%	0.3%	0.3%	0.5%	0.4%	0.3%	0.5%	0.7%	0.6%	0.6%	
PECO	8,480	8,480	8,370	8,386	8,419	8,414	8,411	8,385	8,390	8,417	8,461	8,484	8,471	0.1%
				0.2%	0.4%	-0.1%	-0.0%	-0.3%	0.1%	0.3%	0.5%	0.3%	-0.2%	
PENLC	2,900	2,900	2,812	2,807	2,802	2,806	2,801	2,802	2,808	2,805	2,820	2,834	2,832	0.1%
				-0.2%	-0.2%	0.1%	-0.2%	0.0%	0.2%	-0.1%	0.5%	0.5%	-0.1%	
PEPCO	5,829	5,829	5,902	5,892	5,892	5,912	5,891	5,885	5,846	5,844	5,813	5,787	5,766	(0.2%)
				-0.2%	0.0%	0.3%	-0.4%	-0.1%	-0.7%	-0.0%	-0.5%	-0.4%	-0.4%	
PL	7,314	7,333	7,024	7,023	7,036	7,054	7,072	7,091	7,111	7,139	7,167	7,208	7,237	0.3%
				-0.0%	0.2%	0.3%	0.3%	0.3%	0.3%	0.4%	0.4%	0.6%	0.4%	
PS	10,065	10,065	9,543	9,534	9,535	9,545	9,564	9,590	9,632	9,690	9,745	9,831	9,857	0.3%
				-0.1%	0.0%	0.1%	0.2%	0.3%	0.4%	0.6%	0.6%	0.9%	0.3%	
RECO	428	428	391	389	389	389	388	387	387	388	388	390	388	(0.1%)
				-0.5%	0.0%	0.0%	-0.3%	-0.3%	0.0%	0.3%	0.0%	0.5%	-0.5%	
UGI	217	217	193	192	192	192	192	191	191	190	190	191	191	(0.1%)
				-0.5%	0.0%	0.0%	0.0%	-0.5%	0.0%	-0.5%	0.0%	0.5%	0.0%	
DIVERSITY - MID-ATLANTIC(-)			629	647	746	786	792	794	752	721	809	906	875	
PJM MID-ATLANTIC	56,514	56,539	55,146	55,072	55,007	55,016	55,045	55,053	55,174	55,383	55,457	55,513	55,540	0.1%
				-0.1%	-0.1%	0.0%	0.1%	0.0%	0.2%	0.4%	0.1%	0.1%	0.0%	
FE-EAST	11,925	11,925	11,334	11,296	11,255	11,239	11,251	11,270	11,305	11,341	11,369	11,440	11,504	0.1%
				-0.3%	-0.4%	-0.1%	0.1%	0.2%	0.3%	0.3%	0.2%	0.6%	0.6%	
PLGRP	7,523	7,541	7,204	7,202	7,217	7,228	7,243	7,264	7,280	7,311	7,340	7,376	7,418	0.3%
				-0.0%	0.2%	0.2%	0.2%	0.3%	0.2%	0.4%	0.4%	0.5%	0.6%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2022).
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 2033 - 2037

	2033	2034	2035	2036	2037	Annual Growth Rate (15 yr)
AE	2,552	2,568	2,586	2,589	2,597	0.3%
	0.4%	0.6%	0.7%	0.1%	0.3%	
BGE	6,320	6,313	6,313	6,341	6,351	(0.1%)
	-0.5%	-0.1%	0.0%	0.4%	0.2%	
DPL	3,828	3,809	3,802	3,803	3,809	(0.1%)
	-0.7%	-0.5%	-0.2%	0.0%	0.2%	
JCPL	5,892	5,923	5,954	5,988	6,017	0.2%
	0.4%	0.5%	0.5%	0.6%	0.5%	
METED	3,078	3,087	3,103	3,127	3,151	0.5%
	0.6%	0.3%	0.5%	0.8%	0.8%	
PECO	8,477	8,492	8,516	8,560	8,584	0.2%
	0.1%	0.2%	0.3%	0.5%	0.3%	
PENLC	2,834	2,837	2,838	2,857	2,864	0.1%
	0.1%	0.1%	0.0%	0.7%	0.2%	
PEPCO	5,738	5,697	5,696	5,707	5,702	(0.2%)
	-0.5%	-0.7%	-0.0%	0.2%	-0.1%	
PL	7,265	7,271	7,301	7,344	7,377	0.3%
	0.4%	0.1%	0.4%	0.6%	0.4%	
PS	9,897	9,960	10,019	10,074	10,137	0.4%
	0.4%	0.6%	0.6%	0.5%	0.6%	
RECO	388	389	391	393	393	0.0%
	0.0%	0.3%	0.5%	0.5%	0.0%	
UGI	190	190	190	190	190	(0.1%)
	-0.5%	0.0%	0.0%	0.0%	0.0%	
DIVERSITY - MID-ATLANTIC(-)	857	844	896	1,137	1,067	
PJM MID-ATLANTIC	55,602	55,692	55,813	55,836	56,105	0.1%
	0.1%	0.2%	0.2%	0.0%	0.5%	
FE-EAST	11,535	11,583	11,633	11,696	11,750	0.2%
	0.3%	0.4%	0.4%	0.5%	0.5%	
PLGRP	7,432	7,447	7,472	7,504	7,557	0.3%
	0.2%	0.2%	0.3%	0.4%	0.7%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2022).
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 2022 - 2032

	METERED 2021	UNRESTRICTED 2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Annual Growth Rate (10 yr)
AEP	21,939	21,939	22,183	22,238	22,332	22,376	22,374	22,370	22,382	22,424	22,470	22,492	22,496	0.1%
				0.2%	0.4%	0.2%	-0.0%	-0.0%	0.1%	0.2%	0.2%	0.1%	0.0%	
APS	8,866	8,874	8,675	8,725	8,777	8,813	8,810	8,781	8,769	8,766	8,776	8,766	8,762	0.1%
				0.6%	0.6%	0.4%	-0.0%	-0.3%	-0.1%	-0.0%	0.1%	-0.1%	-0.0%	
ATSI	12,605	12,615	12,273	12,349	12,419	12,442	12,498	12,501	12,499	12,539	12,575	12,568	12,551	0.2%
				0.6%	0.6%	0.2%	0.5%	0.0%	-0.0%	0.3%	0.3%	-0.1%	-0.1%	
COMED	21,168	21,168	20,787	20,638	20,522	20,384	20,321	20,287	20,223	20,225	20,183	20,147	20,121	(0.3%)
				-0.7%	-0.6%	-0.7%	-0.3%	-0.2%	-0.3%	0.0%	-0.2%	-0.2%	-0.1%	
DAYTON	3,317	3,317	3,271	3,267	3,274	3,275	3,278	3,274	3,275	3,278	3,291	3,293	3,288	0.1%
				-0.1%	0.2%	0.0%	0.1%	-0.1%	0.0%	0.1%	0.4%	0.1%	-0.2%	
DEOK	5,306	5,306	5,239	5,269	5,305	5,334	5,357	5,372	5,382	5,397	5,407	5,424	5,427	0.4%
				0.6%	0.7%	0.5%	0.4%	0.3%	0.2%	0.3%	0.2%	0.3%	0.1%	
DLCO	2,760	2,760	2,742	2,759	2,776	2,794	2,804	2,812	2,812	2,818	2,822	2,833	2,837	0.3%
				0.6%	0.6%	0.6%	0.4%	0.3%	0.0%	0.2%	0.1%	0.4%	0.1%	
EKPC	2,095	2,095	2,091	2,117	2,144	2,170	2,195	2,207	2,214	2,215	2,218	2,230	2,228	0.6%
				1.2%	1.3%	1.2%	1.2%	0.5%	0.3%	0.0%	0.1%	0.5%	-0.1%	
OVEC	81	81	90	90	90	90	90	90	90	90	90	90	90	0.0%
				0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
DIVERSITY - WESTERN(-)			1,647	1,702	1,609	1,636	1,665	1,716	1,686	1,688	1,695	1,719	1,674	
PJM WESTERN	77,226	77,236	75,704	75,750	76,030	76,042	76,062	75,978	75,960	76,064	76,137	76,124	76,126	0.1%
				0.1%	0.4%	0.0%	0.0%	-0.1%	-0.0%	0.1%	0.1%	-0.0%	0.0%	
DOM	20,409	20,409	20,424	21,013	21,751	22,568	23,375	23,681	23,990	24,358	24,708	25,085	25,434	2.2%
				2.9%	3.5%	3.8%	3.6%	1.3%	1.3%	1.5%	1.4%	1.5%	1.4%	
DIVERSITY - TOTAL(-)			4,612	4,833	4,834	4,883	4,680	4,900	4,873	4,880	5,031	5,072	5,268	
PJM RTO	148,421	148,433	148,938	149,351	150,309	151,165	152,259	152,322	152,689	153,334	153,775	154,275	154,381	0.4%
				0.3%	0.6%	0.6%	0.7%	0.0%	0.2%	0.4%	0.3%	0.3%	0.1%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2022).
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 2033 - 2037

	2033	2034	2035	2036	2037	Annual Growth Rate (15 yr)
AEP	22,531	22,565	22,616	22,679	22,711	0.2%
	0.2%	0.2%	0.2%	0.3%	0.1%	
APS	8,747	8,751	8,757	8,784	8,795	0.1%
	-0.2%	0.0%	0.1%	0.3%	0.1%	
ATSI	12,552	12,532	12,589	12,612	12,629	0.2%
	0.0%	-0.2%	0.5%	0.2%	0.1%	
COMED	20,093	20,009	20,036	20,017	19,960	(0.3%)
	-0.1%	-0.4%	0.1%	-0.1%	-0.3%	
DAYTON	3,291	3,291	3,297	3,310	3,316	0.1%
	0.1%	0.0%	0.2%	0.4%	0.2%	
DEOK	5,435	5,444	5,462	5,480	5,500	0.3%
	0.1%	0.2%	0.3%	0.3%	0.4%	
DLCO	2,829	2,829	2,835	2,844	2,850	0.3%
	-0.3%	0.0%	0.2%	0.3%	0.2%	
EKPC	2,238	2,243	2,246	2,254	2,260	0.5%
	0.4%	0.2%	0.1%	0.4%	0.3%	
OVEC	90	90	90	90	90	0.0%
	0.0%	0.0%	0.0%	0.0%	0.0%	
DIVERSITY - WESTERN(-)	1,627	1,621	1,604	1,604	1,618	
PJM WESTERN	76,179	76,133	76,324	76,466	76,493	0.1%
	0.1%	-0.1%	0.3%	0.2%	0.0%	
DOM	25,807	26,136	26,568	26,994	27,354	2.0%
	1.5%	1.3%	1.7%	1.6%	1.3%	
DIVERSITY - TOTAL(-)	5,305	5,449	5,070	5,337	4,948	
PJM RTO	154,767	154,977	156,135	156,700	157,689	0.4%
	0.3%	0.1%	0.7%	0.4%	0.6%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2022).
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 2021/22 - 2031/32

	METERED 20/21	UNRESTRICTED 20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32	Annual Growth Rate (10 yr)
AE	1,596	1,596	1,610	1,619	1,624	1,636	1,646	1,656	1,666	1,672	1,687	1,698	1,710	0.6%
				0.6%	0.3%	0.7%	0.6%	0.6%	0.6%	0.4%	0.9%	0.7%	0.7%	
BGE	5,034	5,034	5,780	5,802	5,849	5,880	5,915	5,957	6,000	6,032	6,060	6,095	6,131	0.6%
				0.4%	0.8%	0.5%	0.6%	0.7%	0.7%	0.5%	0.5%	0.6%	0.6%	
DPL	3,232	3,232	3,596	3,628	3,653	3,672	3,694	3,718	3,749	3,770	3,810	3,824	3,847	0.7%
				0.9%	0.7%	0.5%	0.6%	0.6%	0.8%	0.6%	1.1%	0.4%	0.6%	
JCPL	3,508	3,508	3,700	3,710	3,728	3,745	3,771	3,799	3,828	3,850	3,880	3,908	3,939	0.6%
				0.3%	0.5%	0.5%	0.7%	0.7%	0.8%	0.6%	0.8%	0.7%	0.8%	
METED	2,453	2,453	2,605	2,600	2,602	2,599	2,603	2,606	2,611	2,615	2,626	2,628	2,633	0.1%
				-0.2%	0.1%	-0.1%	0.2%	0.1%	0.2%	0.2%	0.4%	0.1%	0.2%	
PECO	6,139	6,144	6,634	6,636	6,646	6,644	6,645	6,648	6,650	6,644	6,659	6,652	6,660	0.0%
				0.0%	0.2%	-0.0%	0.0%	0.0%	0.0%	-0.1%	0.2%	-0.1%	0.1%	
PENLC	2,600	2,600	2,781	2,775	2,776	2,773	2,772	2,769	2,769	2,763	2,773	2,767	2,767	(0.1%)
				-0.2%	0.0%	-0.1%	-0.0%	-0.1%	0.0%	-0.2%	0.4%	-0.2%	0.0%	
PEPCO	4,582	4,582	5,331	5,381	5,422	5,443	5,451	5,466	5,485	5,486	5,479	5,483	5,494	0.3%
				0.9%	0.8%	0.4%	0.1%	0.3%	0.3%	0.0%	-0.1%	0.1%	0.2%	
PL	6,528	6,528	7,252	7,249	7,260	7,261	7,271	7,284	7,312	7,327	7,330	7,347	7,355	0.1%
				-0.0%	0.2%	0.0%	0.1%	0.2%	0.4%	0.2%	0.0%	0.2%	0.1%	
PS	6,242	6,242	6,657	6,690	6,745	6,792	6,853	6,913	6,969	7,019	7,077	7,144	7,219	0.8%
				0.5%	0.8%	0.7%	0.9%	0.9%	0.8%	0.7%	0.8%	0.9%	1.0%	
RECO	207	207	227	228	229	229	231	232	234	234	236	237	238	0.5%
				0.4%	0.4%	0.0%	0.9%	0.4%	0.9%	0.0%	0.9%	0.4%	0.4%	
UGI	188	188	199	199	198	197	197	196	196	195	195	194	194	(0.3%)
				0.0%	-0.5%	-0.5%	0.0%	-0.5%	0.0%	-0.5%	0.0%	-0.5%	0.0%	
DIVERSITY - MID-ATLANTIC(-)			560	563	663	747	794	681	588	700	681	751	740	
PJM MID-ATLANTIC	41,441	41,447	45,812	45,954	46,069	46,124	46,255	46,563	46,881	46,907	47,131	47,226	47,447	0.4%
				0.3%	0.3%	0.1%	0.3%	0.7%	0.7%	0.1%	0.5%	0.2%	0.5%	
FE-EAST	8,517	8,517	9,000	8,999	9,014	9,005	9,034	9,092	9,128	9,139	9,188	9,188	9,225	0.2%
				-0.0%	0.2%	-0.1%	0.3%	0.6%	0.4%	0.1%	0.5%	0.0%	0.4%	
PLGRP	6,706	6,706	7,445	7,440	7,455	7,454	7,460	7,476	7,500	7,516	7,517	7,536	7,544	0.1%
				-0.1%	0.2%	-0.0%	0.1%	0.2%	0.3%	0.2%	0.0%	0.3%	0.1%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2021/22).
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 2032/33 - 2036/37

	32/33	33/34	34/35	35/36	36/37	Annual Growth Rate (15 yr)
AE	1,721	1,732	1,744	1,772	1,789	0.7%
	0.6%	0.6%	0.7%	1.6%	1.0%	
BGE	6,178	6,209	6,249	6,308	6,360	0.6%
	0.8%	0.5%	0.6%	0.9%	0.8%	
DPL	3,878	3,910	3,930	3,970	3,975	0.7%
	0.8%	0.8%	0.5%	1.0%	0.1%	
JCPL	3,973	4,000	4,027	4,081	4,112	0.7%
	0.9%	0.7%	0.7%	1.3%	0.8%	
METED	2,639	2,650	2,655	2,658	2,656	0.1%
	0.2%	0.4%	0.2%	0.1%	-0.1%	
PECO	6,674	6,687	6,679	6,694	6,687	0.1%
	0.2%	0.2%	-0.1%	0.2%	-0.1%	
PENLC	2,767	2,765	2,765	2,768	2,761	(0.0%)
	0.0%	-0.1%	0.0%	0.1%	-0.3%	
PEPCO	5,520	5,521	5,547	5,582	5,628	0.4%
	0.5%	0.0%	0.5%	0.6%	0.8%	
PL	7,388	7,399	7,410	7,410	7,413	0.1%
	0.4%	0.1%	0.1%	0.0%	0.0%	
PS	7,289	7,348	7,412	7,501	7,587	0.9%
	1.0%	0.8%	0.9%	1.2%	1.1%	
RECO	240	241	243	245	246	0.5%
	0.8%	0.4%	0.8%	0.8%	0.4%	
UGI	194	194	193	193	193	(0.2%)
	0.0%	0.0%	-0.5%	0.0%	0.0%	
DIVERSITY - MID-ATLANTIC(-)	588	633	695	715	722	
PJM MID-ATLANTIC	47,873	48,023	48,159	48,467	48,685	0.4%
	0.9%	0.3%	0.3%	0.6%	0.4%	
FE-EAST	9,298	9,329	9,353	9,430	9,430	0.3%
	0.8%	0.3%	0.3%	0.8%	0.0%	
PLGRP	7,573	7,584	7,594	7,594	7,602	0.1%
	0.4%	0.1%	0.1%	0.0%	0.1%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2021/22).
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
2021/22 - 2031/32

	METERED 20/21	UNRESTRICTED 20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32	Annual Growth Rate (10 yr)
AEP	19,969	19,969	22,348	22,382	22,507	22,529	22,672	22,712	22,787	22,820	22,863	22,849	22,946	0.3%
				0.2%	0.6%	0.1%	0.6%	0.2%	0.3%	0.1%	0.2%	-0.1%	0.4%	
APS	7,909	7,909	9,009	9,048	9,128	9,148	9,183	9,217	9,245	9,240	9,293	9,312	9,338	0.4%
				0.4%	0.9%	0.2%	0.4%	0.4%	0.3%	-0.1%	0.6%	0.2%	0.3%	
ATSI	9,530	9,530	10,064	10,097	10,160	10,150	10,179	10,175	10,192	10,173	10,178	10,154	10,172	0.1%
				0.3%	0.6%	-0.1%	0.3%	-0.0%	0.2%	-0.2%	0.0%	-0.2%	0.2%	
COMED	14,120	14,120	15,073	15,046	15,055	15,008	15,051	15,122	15,226	15,176	15,226	15,254	15,303	0.2%
				-0.2%	0.1%	-0.3%	0.3%	0.5%	0.7%	-0.3%	0.3%	0.2%	0.3%	
DAYTON	2,780	2,780	2,940	2,939	2,947	2,944	2,952	2,957	2,962	2,963	2,963	2,958	2,965	0.1%
				-0.0%	0.3%	-0.1%	0.3%	0.2%	0.2%	0.0%	0.0%	-0.2%	0.2%	
DEOK	4,226	4,226	4,555	4,570	4,604	4,611	4,621	4,643	4,684	4,668	4,691	4,687	4,694	0.3%
				0.3%	0.7%	0.2%	0.2%	0.5%	0.9%	-0.3%	0.5%	-0.1%	0.1%	
DLCO	1,818	1,818	1,995	2,003	2,010	2,010	2,023	2,027	2,030	2,028	2,027	2,029	2,042	0.2%
				0.4%	0.3%	0.0%	0.6%	0.2%	0.1%	-0.1%	-0.0%	0.1%	0.6%	
EKPC	2,439	2,439	2,666	2,690	2,703	2,714	2,723	2,731	2,741	2,746	2,760	2,767	2,776	0.4%
				0.9%	0.5%	0.4%	0.3%	0.3%	0.4%	0.2%	0.5%	0.3%	0.3%	
OVEC	106	106	115	115	115	115	115	115	115	115	115	115	115	0.0%
				0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
DIVERSITY - WESTERN(-)			1,532	1,523	1,502	1,520	1,512	1,403	1,528	1,497	1,479	1,568	1,530	
PJM WESTERN	61,056	61,056	67,233	67,367	67,727	67,709	68,007	68,296	68,454	68,432	68,637	68,557	68,821	0.2%
				0.2%	0.5%	-0.0%	0.4%	0.4%	0.2%	-0.0%	0.3%	-0.1%	0.4%	
DOM	17,868	17,868	20,762	21,460	22,283	23,196	24,167	24,853	25,249	25,640	26,020	26,404	26,810	2.6%
				3.4%	3.8%	4.1%	4.2%	2.8%	1.6%	1.5%	1.5%	1.5%	1.5%	
DIVERSITY - TOTAL(-)			3,797	3,887	3,884	3,775	3,812	3,853	3,891	3,858	3,839	3,824	3,832	
PJM RTO	117,011	117,012	132,102	132,980	134,360	135,521	136,923	137,943	138,809	139,318	140,109	140,682	141,516	0.7%
				0.7%	1.0%	0.9%	1.0%	0.7%	0.6%	0.4%	0.6%	0.4%	0.6%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2021/22).
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
2032/33 - 2036/37

	32/33	33/34	34/35	35/36	36/37	Annual Growth Rate (15 yr)
AEP	23,013	23,036	23,092	23,146	23,175	0.2%
	0.3%	0.1%	0.2%	0.2%	0.1%	
APS	9,359	9,383	9,409	9,436	9,454	0.3%
	0.2%	0.3%	0.3%	0.3%	0.2%	
ATSI	10,180	10,177	10,169	10,156	10,153	0.1%
	0.1%	-0.0%	-0.1%	-0.1%	-0.0%	
COMED	15,436	15,450	15,491	15,533	15,544	0.2%
	0.9%	0.1%	0.3%	0.3%	0.1%	
DAYTON	2,976	2,981	2,987	2,991	2,995	0.1%
	0.4%	0.2%	0.2%	0.1%	0.1%	
DEOK	4,741	4,747	4,760	4,768	4,765	0.3%
	1.0%	0.1%	0.3%	0.2%	-0.1%	
DLCO	2,046	2,048	2,043	2,044	2,057	0.2%
	0.2%	0.1%	-0.2%	0.0%	0.6%	
EKPC	2,785	2,794	2,802	2,812	2,819	0.4%
	0.3%	0.3%	0.3%	0.4%	0.2%	
OVEC	115	115	115	115	115	0.0%
	0.0%	0.0%	0.0%	0.0%	0.0%	
DIVERSITY - WESTERN(-)	1,524	1,492	1,523	1,529	1,544	
PJM WESTERN	69,127	69,239	69,345	69,472	69,533	0.2%
	0.4%	0.2%	0.2%	0.2%	0.1%	
DOM	27,189	27,567	27,923	28,322	28,716	2.2%
	1.4%	1.4%	1.3%	1.4%	1.4%	
DIVERSITY - TOTAL(-)	3,987	3,987	4,010	3,865	3,980	
PJM RTO	142,314	142,967	143,635	144,640	145,220	0.6%
	0.6%	0.5%	0.5%	0.7%	0.4%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2021/22).
Winter season indicates peak from December, January, February.

Table B-3

SPRING PEAK LOAD (MW) FOR
EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2022 - 2037

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
AE	1,522	1,516	1,516	1,497	1,493	1,497	1,508	1,520	1,525	1,530	1,545	1,558	1,572	1,579	1,594	1,606
BGE	5,086	5,074	5,076	5,076	5,076	5,101	5,126	5,143	5,156	5,154	5,183	5,204	5,206	5,225	5,243	5,297
DPL	2,984	2,990	2,979	2,971	2,974	2,984	3,000	3,014	3,026	3,023	3,032	3,036	3,049	3,053	3,056	3,076
JCPL	3,894	3,867	3,861	3,828	3,814	3,814	3,861	3,890	3,915	3,929	3,920	3,954	3,998	4,028	4,054	4,071
METED	2,401	2,398	2,393	2,391	2,395	2,399	2,419	2,425	2,431	2,424	2,435	2,451	2,462	2,465	2,456	2,460
PECO	6,381	6,389	6,389	6,328	6,292	6,294	6,362	6,381	6,398	6,353	6,345	6,404	6,418	6,443	6,411	6,398
PENLC	2,458	2,443	2,432	2,414	2,410	2,404	2,403	2,407	2,410	2,404	2,418	2,426	2,424	2,424	2,418	2,428
PEPCO	4,665	4,660	4,676	4,638	4,632	4,628	4,643	4,637	4,611	4,573	4,590	4,605	4,602	4,611	4,615	4,635
PL	6,214	6,200	6,210	6,210	6,229	6,248	6,243	6,260	6,281	6,273	6,307	6,314	6,324	6,330	6,322	6,355
PS	6,955	6,942	6,993	6,930	6,899	6,898	6,997	7,085	7,152	7,145	7,133	7,193	7,286	7,386	7,433	7,436
RECO	271	269	268	262	258	257	261	262	263	259	258	260	263	263	262	260
UGI	169	167	166	165	165	165	164	164	163	163	163	163	163	162	161	161
DIVERSITY - MID-ATLANTIC(-)	2,355	2,379	2,386	2,256	2,283	2,297	2,286	2,305	2,362	2,235	2,284	2,309	2,370	2,454	2,380	2,421
PJM MID-ATLANTIC	40,645	40,536	40,573	40,454	40,354	40,392	40,701	40,883	40,969	40,995	41,045	41,259	41,397	41,515	41,645	41,762
FE-EAST	8,205	8,151	8,111	8,049	8,008	8,026	8,096	8,129	8,159	8,162	8,187	8,259	8,310	8,337	8,362	8,389
PLGRP	6,354	6,332	6,356	6,356	6,376	6,389	6,368	6,384	6,414	6,411	6,449	6,456	6,459	6,457	6,463	6,495

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, 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
2022 - 2037

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
AEP	19,381	19,393	19,483	19,506	19,549	19,613	19,623	19,656	19,642	19,654	19,752	19,803	19,817	19,850	19,828	19,877
APS	7,765	7,783	7,828	7,853	7,881	7,889	7,899	7,909	7,903	7,912	7,955	7,965	7,978	7,991	7,998	8,037
ATSI	9,639	9,670	9,706	9,685	9,655	9,678	9,761	9,794	9,783	9,743	9,714	9,785	9,795	9,803	9,744	9,712
COMED	14,823	14,710	14,597	14,389	14,297	14,264	14,387	14,420	14,413	14,249	14,207	14,264	14,271	14,301	14,235	14,164
DAYTON	2,627	2,616	2,614	2,607	2,605	2,604	2,627	2,631	2,628	2,617	2,615	2,639	2,643	2,647	2,636	2,642
DEOK	4,233	4,245	4,260	4,232	4,224	4,237	4,299	4,334	4,310	4,291	4,299	4,359	4,369	4,401	4,366	4,366
DLCO	2,150	2,159	2,173	2,162	2,158	2,167	2,191	2,199	2,209	2,193	2,196	2,213	2,217	2,223	2,221	2,213
EKPC	2,054	2,078	2,099	2,115	2,133	2,150	2,154	2,153	2,157	2,161	2,178	2,175	2,177	2,177	2,185	2,186
OVEC	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115
DIVERSITY - WESTERN(-)	2,792	2,903	2,949	2,892	3,006	2,970	2,931	3,058	3,043	3,102	3,006	2,980	2,932	2,949	3,073	2,828
PJM WESTERN	59,995	59,866	59,926	59,772	59,611	59,747	60,125	60,153	60,117	59,833	60,025	60,338	60,450	60,559	60,255	60,484
DOM	17,634	18,262	19,000	19,829	20,697	21,193	21,521	21,859	22,211	22,576	22,931	23,284	23,636	23,996	24,354	24,757
DIVERSITY - TOTAL(-)	6,984	7,077	6,954	7,279	7,173	7,127	6,921	6,924	7,215	6,943	6,919	7,036	7,131	7,237	7,137	6,990
PJM RTO	116,437	116,869	117,880	117,924	118,778	119,472	120,643	121,334	121,487	121,798	122,372	123,134	123,654	124,236	124,570	125,262

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, 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
2022 - 2037

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
AE	1,884	1,878	1,869	1,863	1,859	1,864	1,877	1,883	1,893	1,905	1,919	1,932	1,943	1,954	1,975	1,990
BGE	5,423	5,417	5,422	5,436	5,446	5,459	5,471	5,486	5,512	5,523	5,532	5,533	5,551	5,575	5,610	5,652
DPL	3,169	3,182	3,187	3,192	3,194	3,204	3,225	3,244	3,242	3,255	3,239	3,248	3,246	3,243	3,264	3,276
JCPL	4,463	4,457	4,453	4,452	4,452	4,466	4,492	4,522	4,558	4,592	4,620	4,649	4,689	4,728	4,776	4,814
METED	2,452	2,449	2,449	2,452	2,454	2,463	2,469	2,479	2,502	2,519	2,533	2,546	2,556	2,569	2,594	2,611
PECO	6,892	6,900	6,895	6,895	6,891	6,896	6,892	6,903	6,928	6,960	6,964	6,981	6,984	6,997	7,048	7,071
PENLC	2,453	2,446	2,435	2,427	2,419	2,422	2,425	2,429	2,436	2,445	2,448	2,444	2,440	2,444	2,465	2,471
PEPCO	4,971	4,976	4,958	4,961	4,949	4,945	4,941	4,917	4,905	4,899	4,891	4,881	4,876	4,874	4,919	4,925
PL	6,063	6,066	6,047	6,043	6,058	6,088	6,102	6,118	6,133	6,160	6,204	6,227	6,250	6,269	6,274	6,317
PS	7,877	7,885	7,921	7,963	7,958	7,994	8,028	8,089	8,194	8,274	8,312	8,374	8,424	8,478	8,604	8,652
RECO	298	295	293	293	291	291	291	291	293	295	295	295	295	296	300	299
UGI	164	164	162	161	162	162	161	161	160	159	160	160	159	159	158	158
DIVERSITY - MID-ATLANTIC(-)	1,218	1,290	1,322	1,301	1,244	1,287	1,333	1,495	1,408	1,393	1,339	1,424	1,530	1,633	1,533	1,555
PJM MID-ATLANTIC	44,891	44,825	44,769	44,837	44,889	44,967	45,041	45,027	45,348	45,593	45,778	45,846	45,883	45,953	46,454	46,681
FE-EAST	9,094	9,026	9,010	9,036	9,036	9,048	9,035	9,073	9,150	9,236	9,280	9,290	9,322	9,366	9,497	9,548
PLGRP	6,215	6,215	6,196	6,191	6,206	6,233	6,249	6,266	6,277	6,304	6,350	6,376	6,398	6,411	6,416	6,463

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, 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
2022 - 2037

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
AEP	19,977	20,077	20,138	20,226	20,256	20,264	20,283	20,278	20,313	20,407	20,440	20,473	20,461	20,488	20,613	20,725
APS	7,636	7,655	7,659	7,685	7,696	7,704	7,726	7,728	7,736	7,758	7,786	7,803	7,822	7,830	7,858	7,893
ATSI	10,513	10,548	10,617	10,709	10,741	10,712	10,669	10,685	10,729	10,831	10,776	10,761	10,728	10,738	10,879	10,884
COMED	17,178	17,049	16,886	16,882	16,834	16,820	16,694	16,588	16,665	16,830	16,761	16,729	16,668	16,574	16,871	16,903
DAYTON	2,858	2,856	2,858	2,874	2,878	2,867	2,858	2,855	2,872	2,894	2,887	2,884	2,876	2,881	2,919	2,928
DEOK	4,766	4,784	4,812	4,847	4,869	4,885	4,883	4,876	4,909	4,937	4,949	4,961	4,955	4,950	5,007	5,027
DLCO	2,382	2,402	2,417	2,437	2,451	2,458	2,464	2,462	2,473	2,487	2,490	2,493	2,495	2,489	2,509	2,517
EKPC	2,004	2,026	2,043	2,066	2,096	2,102	2,106	2,109	2,110	2,118	2,126	2,130	2,134	2,138	2,143	2,153
OVEC	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
DIVERSITY - WESTERN(-)	1,624	1,619	1,625	1,692	1,518	1,660	1,594	1,692	1,619	1,602	1,424	1,671	1,519	1,571	1,377	1,488
PJM WESTERN	65,760	65,848	65,875	66,104	66,373	66,222	66,159	65,959	66,258	66,730	66,861	66,633	66,690	66,587	67,492	67,612
DOM	18,134	18,776	19,515	20,348	21,082	21,421	21,789	22,101	22,436	22,825	23,218	23,584	23,954	24,323	24,711	25,081
DIVERSITY - TOTAL(-)	6,235	6,484	6,588	6,499	6,499	6,394	6,907	7,291	6,989	6,959	6,787	7,034	7,319	7,495	7,538	7,655
PJM RTO	125,392	125,874	126,518	127,783	128,607	129,163	129,009	128,983	130,080	131,184	131,833	132,124	132,257	132,572	134,029	134,762

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, 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 2022	1,610	5,780	3,596	3,700	2,605	6,634	2,781	5,331	7,252	6,657	227	199	560	45,812
Feb 2022	1,521	5,387	3,375	3,485	2,487	6,239	2,690	5,070	6,865	6,303	213	187	704	43,118
Mar 2022	1,302	4,986	2,984	3,001	2,377	5,546	2,458	4,588	6,214	5,679	178	169	843	38,639
Apr 2022	1,185	4,153	2,427	2,710	2,090	5,015	2,205	3,756	5,209	5,198	183	139	1,048	33,222
May 2022	1,522	5,086	2,881	3,894	2,401	6,381	2,247	4,665	5,503	6,955	271	144	1,305	40,645
Jun 2022	2,181	5,911	3,515	5,228	2,749	7,700	2,661	5,484	6,526	8,775	363	178	720	50,551
Jul 2022	2,488	6,414	3,873	5,831	2,934	8,370	2,812	5,902	7,024	9,543	391	193	629	55,146
Aug 2022	2,403	6,214	3,685	5,489	2,917	8,092	2,673	5,739	6,719	9,200	366	183	303	53,377
Sep 2022	1,884	5,423	3,169	4,463	2,452	6,892	2,453	4,971	6,063	7,877	298	160	1,214	44,891
Oct 2022	1,414	4,096	2,439	3,170	1,990	5,174	2,180	3,878	5,060	6,005	213	138	1,592	34,165
Nov 2022	1,311	4,454	2,675	3,043	2,174	5,216	2,354	4,073	5,866	5,619	193	164	1,046	36,096
Dec 2022	1,578	5,228	3,256	3,632	2,464	6,262	2,641	4,896	6,626	6,501	227	188	562	42,937

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	DIVERSITY	MID-ATLANTIC
Jan 2023	1,619	5,802	3,628	3,710	2,600	6,636	2,775	5,381	7,249	6,690	228	199	563	45,954
Feb 2023	1,529	5,425	3,395	3,487	2,480	6,244	2,682	5,119	6,844	6,340	214	186	732	43,213
Mar 2023	1,298	4,902	2,990	2,966	2,372	5,509	2,443	4,601	6,200	5,661	176	167	895	38,390
Apr 2023	1,180	4,113	2,419	2,665	2,075	4,971	2,184	3,722	5,112	5,169	181	137	1,022	32,906
May 2023	1,516	5,074	2,883	3,867	2,398	6,389	2,242	4,660	5,508	6,942	269	143	1,355	40,536
Jun 2023	2,183	5,878	3,513	5,164	2,736	7,751	2,656	5,466	6,519	8,715	360	177	702	50,416
Jul 2023	2,490	6,391	3,882	5,799	2,934	8,386	2,807	5,892	7,023	9,534	389	192	647	55,072
Aug 2023	2,404	6,191	3,691	5,433	2,921	8,150	2,669	5,742	6,709	9,199	363	182	245	53,409
Sep 2023	1,878	5,417	3,182	4,457	2,449	6,900	2,446	4,976	6,066	7,885	295	158	1,284	44,825
Oct 2023	1,416	4,138	2,456	3,182	2,012	5,243	2,192	3,905	5,114	6,045	211	137	1,610	34,441
Nov 2023	1,316	4,495	2,685	3,046	2,186	5,222	2,365	4,111	5,921	5,634	192	164	1,137	36,200
Dec 2023	1,576	5,266	3,276	3,649	2,463	6,269	2,641	4,931	6,632	6,528	227	187	659	42,986

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	DIVERSITY	MID-ATLANTIC
Jan 2024	1,624	5,849	3,653	3,728	2,602	6,646	2,776	5,422	7,260	6,745	229	198	663	46,069
Feb 2024	1,536	5,471	3,420	3,511	2,479	6,253	2,683	5,148	6,848	6,385	215	185	735	43,399
Mar 2024	1,292	4,873	2,979	2,941	2,361	5,464	2,432	4,613	6,210	5,658	173	166	832	38,330
Apr 2024	1,183	4,118	2,413	2,655	2,081	4,985	2,190	3,757	5,213	5,202	181	138	1,174	32,942
May 2024	1,516	5,076	2,900	3,861	2,393	6,389	2,234	4,676	5,498	6,993	268	144	1,375	40,573
Jun 2024	2,185	5,836	3,485	5,109	2,678	7,639	2,624	5,417	6,487	8,600	356	175	967	49,624
Jul 2024	2,493	6,389	3,893	5,771	2,942	8,419	2,802	5,892	7,036	9,535	389	192	746	55,007
Aug 2024	2,400	6,155	3,670	5,385	2,899	8,054	2,658	5,716	6,714	9,147	361	182	395	52,946
Sep 2024	1,869	5,422	3,187	4,453	2,449	6,895	2,435	4,958	6,047	7,921	293	159	1,319	44,769
Oct 2024	1,414	4,142	2,456	3,159	2,013	5,236	2,171	3,911	5,101	6,088	210	137	1,457	34,581
Nov 2024	1,301	4,484	2,652	3,010	2,168	5,153	2,315	4,054	5,834	5,626	189	162	1,086	35,862
Dec 2024	1,588	5,351	3,283	3,655	2,446	6,244	2,628	4,934	6,639	6,586	226	186	839	42,927

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, 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	OVEC	WESTERN DIVERSITY	PJM WESTERN	DOM	TOTAL DIVERSITY	PJM RTO
Jan 2022	22,348	9,009	10,064	15,073	2,940	4,555	1,995	2,666	115	1,532	67,233	20,762	3,797	132,102
Feb 2022	21,144	8,518	9,692	14,343	2,780	4,276	1,908	2,408	115	1,677	63,507	19,432	3,273	125,165
Mar 2022	19,381	7,765	9,125	12,586	2,584	3,852	1,771	2,054	115	473	58,760	17,634	833	115,516
Apr 2022	16,438	6,536	8,127	11,506	2,222	3,489	1,679	1,607	70	627	51,047	15,297	796	100,445
May 2022	18,301	7,058	9,639	14,823	2,627	4,233	2,150	1,600	70	506	59,995	17,433	3,447	116,437
Jun 2022	20,710	8,081	11,506	18,917	3,020	4,925	2,563	1,968	70	2,069	69,691	19,270	5,228	137,073
Jul 2022	22,183	8,675	12,273	20,787	3,271	5,239	2,742	2,091	90	1,647	75,704	20,424	4,612	148,938
Aug 2022	21,858	8,443	11,822	19,971	3,192	5,113	2,638	2,054	90	2,029	73,152	20,351	5,204	144,008
Sep 2022	19,977	7,636	10,513	17,178	2,858	4,766	2,382	1,932	70	1,552	65,760	18,134	6,159	125,392
Oct 2022	15,992	6,325	8,073	12,375	2,213	3,516	1,770	1,594	70	2,055	49,873	15,440	6,394	96,731
Nov 2022	17,944	7,156	8,572	12,347	2,388	3,621	1,715	2,004	70	1,509	54,308	16,893	4,052	105,800
Dec 2022	20,601	8,306	9,709	14,623	2,742	4,259	1,925	2,383	100	1,191	63,457	19,155	4,062	123,240

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	OVEC	DIVERSITY	WESTERN	DOM	DIVERSITY	PJM RTO
Jan 2023	22,382	9,048	10,097	15,046	2,939	4,570	2,003	2,690	115	1,523	67,367	21,460	3,887	132,980
Feb 2023	21,197	8,557	9,727	14,312	2,780	4,294	1,920	2,430	115	1,722	63,610	20,161	3,620	125,818
Mar 2023	19,393	7,783	9,168	12,528	2,582	3,861	1,781	2,078	115	513	58,776	18,262	979	115,857
Apr 2023	16,273	6,493	8,090	11,400	2,201	3,463	1,685	1,625	70	636	50,664	15,888	1,026	100,090
May 2023	18,308	7,062	9,670	14,710	2,616	4,245	2,159	1,612	70	586	59,866	18,058	3,532	116,869
Jun 2023	20,724	8,117	11,557	18,857	3,009	4,939	2,577	1,984	70	1,996	69,838	19,814	5,440	137,326
Jul 2023	22,238	8,725	12,349	20,638	3,267	5,269	2,759	2,117	90	1,702	75,750	21,013	4,833	149,351
Aug 2023	21,929	8,487	11,900	20,025	3,188	5,135	2,658	2,074	90	2,270	73,216	20,941	5,758	144,323
Sep 2023	20,077	7,655	10,548	17,049	2,856	4,784	2,402	1,956	70	1,549	65,848	18,776	6,408	125,874
Oct 2023	16,120	6,390	8,167	12,343	2,223	3,559	1,799	1,608	70	2,016	50,263	16,277	6,434	98,173
Nov 2023	18,114	7,201	8,664	12,318	2,397	3,659	1,736	2,026	70	1,501	54,684	17,692	4,129	107,085
Dec 2023	20,674	8,379	9,764	14,553	2,747	4,277	1,930	2,371	100	1,094	63,701	19,874	3,880	124,434

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	OVEC	DIVERSITY	WESTERN	DOM	DIVERSITY	PJM RTO
Jan 2024	22,507	9,128	10,160	15,055	2,947	4,604	2,010	2,703	115	1,502	67,727	22,283	3,884	134,360
Feb 2024	21,297	8,634	9,788	14,290	2,792	4,326	1,924	2,435	115	1,639	63,962	20,941	3,623	127,053
Mar 2024	19,483	7,828	9,208	12,461	2,580	3,895	1,789	2,099	115	600	58,858	19,000	705	116,915
Apr 2024	16,634	6,600	8,159	11,376	2,204	3,544	1,705	1,654	70	769	51,177	16,665	824	101,903
May 2024	18,322	7,099	9,706	14,597	2,614	4,260	2,173	1,619	70	534	59,926	18,874	3,402	117,880
Jun 2024	20,586	8,105	11,492	18,555	2,968	4,948	2,573	1,999	70	2,247	69,049	20,454	5,676	136,665
Jul 2024	22,332	8,777	12,419	20,522	3,274	5,305	2,776	2,144	90	1,609	76,030	21,751	4,834	150,309
Aug 2024	21,904	8,507	11,855	19,669	3,153	5,148	2,661	2,096	90	2,109	72,974	21,615	5,236	144,803
Sep 2024	20,138	7,659	10,617	16,886	2,858	4,812	2,417	2,003	70	1,585	65,875	19,515	6,545	126,518
Oct 2024	16,167	6,415	8,217	12,255	2,229	3,600	1,822	1,643	70	2,123	50,295	17,101	6,093	99,464
Nov 2024	17,919	7,123	8,621	12,155	2,361	3,626	1,731	2,043	70	1,468	54,181	18,358	4,577	106,378
Dec 2024	20,672	8,363	9,712	14,501	2,720	4,276	1,926	2,379	100	1,336	63,313	20,724	3,347	125,792

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.

Table B-6

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

	FE_EAST	PLGRP
Jan 2022	9,000	7,445
Feb 2022	8,519	7,039
Mar 2022	7,697	6,354
Apr 2022	6,715	5,346
May 2022	8,205	5,646
Jun 2022	10,363	6,675
Jul 2022	11,334	7,204
Aug 2022	10,885	6,880
Sep 2022	9,094	6,215
Oct 2022	6,987	5,193
Nov 2022	7,398	6,028
Dec 2022	8,618	6,805

	FE_EAST	PLGRP
Jan 2023	8,999	7,440
Feb 2023	8,518	7,019
Mar 2023	7,646	6,332
Apr 2023	6,635	5,238
May 2023	8,151	5,638
Jun 2023	10,266	6,666
Jul 2023	11,296	7,202
Aug 2023	10,842	6,864
Sep 2023	9,026	6,215
Oct 2023	7,052	5,241
Nov 2023	7,418	6,074
Dec 2023	8,623	6,817

	FE_EAST	PLGRP
Jan 2024	9,014	7,455
Feb 2024	8,526	7,010
Mar 2024	7,554	6,356
Apr 2024	6,585	5,349
May 2024	8,111	5,642
Jun 2024	10,141	6,613
Jul 2024	11,255	7,217
Aug 2024	10,786	6,872
Sep 2024	9,010	6,196
Oct 2024	7,024	5,234
Nov 2024	7,330	5,993
Dec 2024	8,564	6,808

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
FE_EAST contains JCPL, METED and PENLC zones. PLGRP contains PL and UGI zones.

Table B-7

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

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
AE																
CAPACITY PERFORMANCE	42	42	42	42	42	42	42	43	43	43	43	43	44	44	44	44
SUMMER PERIOD	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	44	44	44	44	44	44	44	45	45	45	45	45	46	46	46	46
BGE																
CAPACITY PERFORMANCE	120	120	120	120	120	120	120	120	120	120	119	119	119	119	119	119
SUMMER PERIOD	38	38	38	38	38	38	38	38	38	38	38	38	37	37	38	39
PRD	80	153	153	153	154	154	153	154	154	153	152	152	152	152	152	152
TOTAL LOAD MANAGEMENT	238	311	311	311	312	312	311	312	312	311	309	309	308	308	309	310
DPL																
CAPACITY PERFORMANCE	101	101	101	102	102	102	102	102	102	101	100	100	99	99	99	99
SUMMER PERIOD	54	55	55	55	55	55	55	55	55	55	54	54	53	53	53	53
PRD	40	57	57	57	57	58	58	58	58	57	57	56	56	56	56	56
TOTAL LOAD MANAGEMENT	195	213	213	214	214	215	215	215	215	213	211	210	208	208	208	208
JCPL																
CAPACITY PERFORMANCE	87	87	87	87	87	86	86	87	87	88	88	88	89	89	90	91
SUMMER PERIOD	4	4	4	4	4	4	4	4	4	5	5	5	5	5	5	5
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	91	91	91	91	91	90	90	91	91	93	93	93	94	94	95	96
METED																
CAPACITY PERFORMANCE	151	151	151	151	152	153	153	154	155	156	157	158	159	159	161	163
SUMMER PERIOD	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	152	152	152	152	153	154	154	155	156	157	158	159	160	160	162	164

Notes:
Summer-Period DR refers to DR resources that aggregate with Winter-Period resources to form a year-round commitment.
DR Forecast values for each DR Product Type are based on actual committed quantities for Delivery Years 2020/21, 2021/22 and actual cleared quantities in the 2022/23 RPM Base Residual Auction

Table B-7 (Continued)

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

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
PECO																
CAPACITY PERFORMANCE	252	252	253	253	253	252	252	253	254	255	255	255	255	256	257	258
SUMMER PERIOD	0	0	1	1	1	0	0	1	1	1	1	1	1	1	1	1
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	252	252	254	254	254	252	252	254	255	256	256	256	256	257	258	259
PENLC																
CAPACITY PERFORMANCE	219	218	218	218	218	218	218	218	219	220	220	220	221	221	222	223
SUMMER PERIOD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	219	218	218	218	218	218	218	218	219	220	220	220	221	221	222	223
PEPCO																
CAPACITY PERFORMANCE	105	104	104	105	104	104	104	104	103	103	102	102	101	101	101	101
SUMMER PERIOD	86	86	86	87	86	86	86	86	85	85	84	84	83	83	84	85
PRD	110	146	146	146	146	146	145	145	144	143	143	142	141	141	141	141
TOTAL LOAD MANAGEMENT	301	336	336	338	336	336	335	335	332	331	329	328	325	325	326	327
PL																
CAPACITY PERFORMANCE	408	407	408	409	410	411	412	414	415	417	420	420	421	423	424	425
SUMMER PERIOD	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	411	410	411	412	413	414	415	417	418	420	423	423	424	426	427	428
PS																
CAPACITY PERFORMANCE	186	186	186	186	187	187	188	189	190	192	192	193	194	195	197	199
SUMMER PERIOD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	186	186	186	186	187	187	188	189	190	192	192	193	194	195	197	199

Notes:
Summer-Period DR refers to DR resources that aggregate with Winter-Period resources to form a year-round commitment.
DR Forecast values for each DR Product Type are based on actual committed quantities for Delivery Years 2020/21, 2021/22 and actual cleared quantities in the 2022/23 RPM Base Residual Auction

Table B-7 (Continued)

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

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
RECO																
CAPACITY PERFORMANCE	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
SUMMER PERIOD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
UGI																
CAPACITY PERFORMANCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUMMER PERIOD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PJM MID-ATLANTIC																
CAPACITY PERFORMANCE	1,673	1,670	1,672	1,675	1,677	1,677	1,679	1,686	1,690	1,697	1,698	1,700	1,704	1,708	1,716	1,724
SUMMER PERIOD	188	189	190	191	190	189	189	190	189	190	188	188	185	185	187	189
PRD	230	356	356	356	357	358	356	357	356	353	352	350	349	349	349	349
TOTAL LOAD MANAGEMENT	2,091	2,215	2,218	2,222	2,224	2,224	2,224	2,233	2,235	2,240	2,238	2,238	2,238	2,242	2,252	2,262

Notes:
Summer-Period DR refers to DR resources that aggregate with Winter-Period resources to form a year-round commitment.
DR Forecast values for each DR Product Type are based on actual committed quantities for Delivery Years 2020/21, 2021/22 and actual cleared quantities in the 2022/23 RPM Base Residual Auction

Table B-7 (Continued)

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

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
AEP																
CAPACITY PERFORMANCE	1,099	1,102	1,107	1,109	1,109	1,109	1,109	1,111	1,114	1,115	1,115	1,117	1,118	1,121	1,124	1,127
SUMMER PERIOD	10	10	11	11	11	11	11	11	11	11	11	11	11	11	11	11
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	1,109	1,112	1,118	1,120	1,120	1,120	1,120	1,122	1,125	1,126	1,126	1,128	1,129	1,132	1,135	1,138
APS																
CAPACITY PERFORMANCE	530	533	536	538	538	536	536	535	536	535	535	534	535	535	537	539
SUMMER PERIOD	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	530	534	537	539	539	537	537	536	537	536	536	535	536	536	538	540
ATSI																
CAPACITY PERFORMANCE	698	703	707	708	711	711	711	713	716	715	714	714	713	716	718	720
SUMMER PERIOD	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	700	705	709	710	713	713	713	715	718	717	716	716	715	718	720	722
COMED																
CAPACITY PERFORMANCE	1,197	1,189	1,182	1,174	1,170	1,168	1,165	1,165	1,162	1,160	1,159	1,157	1,152	1,154	1,153	1,152
SUMMER PERIOD	110	109	109	108	108	107	107	107	107	107	106	106	106	106	106	106
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	1,307	1,298	1,291	1,282	1,278	1,275	1,272	1,272	1,269	1,267	1,265	1,263	1,258	1,260	1,259	1,258
DAYTON																
CAPACITY PERFORMANCE	153	152	153	153	153	153	153	153	154	154	153	154	154	154	154	154
SUMMER PERIOD	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	160	159	160	160	160	160	160	160	161	161	160	161	161	161	161	161

Notes:
Summer-Period DR refers to DR resources that aggregate with Winter-Period resources to form a year-round commitment.
DR Forecast values for each DR Product Type are based on actual committed quantities for Delivery Years 2020/21, 2021/22 and actual cleared quantities in the 2022/23 RPM Base Residual Auction

Table B-7 (Continued)

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

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
DEOK																
CAPACITY PERFORMANCE	125	126	127	128	128	128	129	129	129	130	130	130	130	131	131	131
SUMMER PERIOD	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	133	134	135	136	136	136	137	137	137	138	138	138	138	139	139	139
DLCO																
CAPACITY PERFORMANCE	75	75	76	76	76	76	76	77	77	77	77	77	77	77	77	77
SUMMER PERIOD	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	82	82	83	83	83	83	83	84	84	84	84	84	84	84	84	84
EKPC																
CAPACITY PERFORMANCE	146	148	150	152	153	154	155	155	155	156	156	157	157	157	158	159
SUMMER PERIOD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	146	148	150	152	153	154	155	155	155	156	156	157	157	157	158	159
PJM WESTERN																
CAPACITY PERFORMANCE	4,023	4,028	4,038	4,038	4,038	4,035	4,034	4,038	4,043	4,042	4,039	4,040	4,036	4,045	4,052	4,059
SUMMER PERIOD	144	144	145	144	144	143	143	143	143	143	142	142	142	142	142	142
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	4,167	4,172	4,183	4,182	4,182	4,178	4,177	4,181	4,186	4,185	4,181	4,182	4,178	4,187	4,194	4,201

Notes:
Summer-Period DR refers to DR resources that aggregate with Winter-Period resources to form a year-round commitment.
DR Forecast values for each DR Product Type are based on actual committed quantities for Delivery Years 2020/21, 2021/22 and actual cleared quantities in the 2022/23 RPM Base Residual Auction

Table B-7 (Continued)

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

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
DOM																
CAPACITY PERFORMANCE	657	676	700	726	752	762	772	783	795	807	818	830	841	854	868	882
SUMMER PERIOD	2	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	659	678	703	729	755	765	775	786	798	810	821	833	844	857	871	885
PJM RTO																
CAPACITY PERFORMANCE	6,353	6,374	6,410	6,439	6,467	6,474	6,485	6,507	6,528	6,546	6,555	6,570	6,581	6,607	6,636	6,665
SUMMER PERIOD	334	335	338	338	337	335	335	336	335	336	333	333	330	330	332	334
PRD	230	356	356	356	357	358	356	357	356	353	352	350	349	349	349	349
TOTAL LOAD MANAGEMENT	6,917	7,065	7,104	7,133	7,161	7,167	7,176	7,200	7,219	7,235	7,240	7,253	7,260	7,286	7,317	7,348

Notes:
Summer-Period DR refers to DR resources that aggregate with Winter-Period resources to form a year-round commitment.
DR Forecast values for each DR Product Type are based on actual committed quantities for Delivery Years 2020/21, 2021/22 and actual cleared quantities in the 2022/23 RPM Base Residual Auction

Table B-8a

DISTRIBUTED SOLAR ADJUSTMENTS TO JULY PEAK LOAD (MW) FOR EACH PJM ZONE AND RTO
2022 - 2037

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
AE	232	239	245	275	286	290	283	293	295	313	317	321	322	328	343	356
BGE	232	266	293	310	304	325	369	394	429	495	541	597	637	682	700	719
DPL	151	163	171	183	190	201	209	224	252	306	357	401	443	471	505	520
JCPL	346	377	409	411	426	470	488	495	510	507	525	538	553	569	576	589
METED	41	41	42	46	46	47	57	56	56	61	63	72	75	76	78	81
PECO	61	66	69	78	79	94	95	107	111	118	130	132	143	161	180	189
PENLC	10	12	18	17	22	27	24	31	35	39	46	52	55	58	64	63
PEPCO	198	227	246	246	255	257	298	309	329	366	376	410	461	478	509	524
PL	88	83	88	111	112	120	110	111	127	151	162	169	172	173	209	218
PS	520	568	641	664	694	707	731	768	777	766	806	835	845	905	919	942
RECO	13	14	15	15	15	17	18	19	19	20	22	23	23	23	23	24
UGI	0	1	1	1	1	1	1	2	2	2	2	2	3	3	3	3
AEP	103	147	189	197	221	261	324	358	407	443	447	472	503	530	576	593
APS	93	106	113	122	141	198	236	273	305	354	382	415	442	469	504	528
ATSI	68	89	126	133	132	120	145	132	153	163	160	175	207	173	194	212
COMED	362	452	551	632	687	733	793	860	938	999	1,037	1,091	1,193	1,203	1,283	1,347
DAYTON	22	29	35	41	43	47	39	42	48	51	53	49	49	52	66	67
DEOK	22	37	42	42	46	49	44	44	61	57	64	57	64	66	80	77
DLCO	14	14	21	27	24	24	30	32	35	39	35	45	48	51	59	57
EKPC	6	7	7	7	7	9	8	13	14	11	17	14	17	21	25	22
OVEC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DOM	541	604	625	662	681	729	819	859	890	916	969	990	1,071	1,050	1,087	1,099
PJM RTO	3,150	3,498	3,821	4,034	4,224	4,647	4,865	5,148	5,642	5,974	6,703	7,109	7,609	7,400	7,856	8,072

Notes:
Adjustment values presented here are reflected in all July peak forecast values.

Table B-8b

DISTRIBUTED BATTERY STORAGE ADJUSTMENT TO SUMMER PEAK LOAD (MW) FOR EACH PJM ZONE AND RTO
2022 - 2037

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
AE	0	0	1	1	2	2	2	3	4	5	6	7	8	9	10	12
BGE	0	1	2	3	4	4	6	7	10	15	21	28	35	44	51	59
DPL	0	1	1	1	2	2	3	3	4	7	9	11	14	16	18	21
JCPL	0	1	2	3	4	4	6	7	10	12	14	16	18	21	24	28
METED	0	0	0	1	1	1	1	2	2	3	4	4	5	6	7	8
PECO	0	1	1	2	2	3	4	5	6	7	9	11	13	15	17	20
PENLC	0	0	1	1	1	1	2	2	3	3	4	5	6	7	8	9
PEPCO	0	1	2	3	4	4	5	7	9	13	16	21	25	30	34	38
PL	0	1	1	2	2	3	4	5	6	7	9	11	14	16	18	21
PS	0	2	4	6	7	9	11	14	19	23	27	31	36	41	46	53
RECO	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	2
UGI	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
AEP	1	1	3	4	5	7	9	11	15	18	22	26	32	38	45	54
APS	0	1	2	2	3	4	5	6	8	10	13	17	20	25	29	33
ATSI	0	1	1	2	3	3	4	6	7	9	11	14	16	20	24	29
COMED	1	3	5	8	10	12	16	20	25	31	39	46	53	62	74	87
DAYTON	0	0	0	0	1	1	1	1	2	2	3	3	4	5	6	8
DEOK	0	0	0	1	1	1	2	2	3	3	4	5	6	7	9	11
DLCO	0	0	0	1	1	1	1	2	2	3	3	4	5	5	6	7
EKPC	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1
OVEC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DOM	1	2	5	7	9	12	16	20	27	34	42	52	63	76	90	107
PJM RTO	5	17	33	47	60	76	96	125	161	206	258	314	375	445	521	610

Notes:
Adjustment values presented here are reflected in all summer peak forecast values.

Table B-8c

PLUG IN ELECTRIC VEHICLE ADJUSTMENT TO SUMMER PEAK LOAD (MW) FOR EACH PJM ZONE AND RTO
2022 - 2037

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
AE	10	14	18	23	29	35	41	46	52	58	64	69	74	79	88	91
BGE	28	40	52	66	83	101	118	135	152	169	186	202	218	233	257	268
DPL	9	12	14	17	21	25	29	33	37	41	44	48	51	54	60	62
JCPL	24	34	43	54	68	82	96	109	122	136	149	162	175	187	206	215
METED	4	4	5	5	6	6	7	7	8	8	9	9	9	10	10	11
PECO	11	12	13	14	15	17	18	20	21	22	23	24	25	26	28	29
PENLC	4	4	4	5	5	6	6	7	7	8	8	8	9	9	10	10
PEPCO	23	34	44	55	70	84	99	113	127	141	156	169	183	195	216	226
PL	9	10	11	12	13	15	16	17	18	19	20	21	22	23	25	25
PS	39	56	72	90	113	136	159	181	204	226	248	270	291	311	343	357
RECO	2	2	3	4	5	5	6	7	8	9	10	11	12	12	14	14
UGI	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1
AEP	21	24	28	37	48	57	67	75	83	91	98	104	110	114	124	126
APS	13	16	19	24	30	36	42	47	53	58	63	68	73	77	84	87
ATSI	12	14	15	16	18	19	21	22	24	25	26	27	28	29	32	32
COMED	53	75	96	121	152	183	214	243	273	303	332	361	388	413	455	473
DAYTON	3	4	4	4	5	5	6	6	6	7	7	7	8	8	9	9
DEOK	5	5	6	6	7	8	8	9	9	10	10	11	11	12	13	13
DLCO	4	4	4	5	5	5	6	6	7	7	8	8	8	9	9	9
EKPC	1	1	1	2	2	2	2	2	2	3	3	3	3	3	3	3
OVEC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DOM	32	41	56	100	147	192	234	272	309	343	374	401	426	446	482	492
PJM RTO	307	406	509	661	842	1,020	1,194	1,359	1,523	1,683	1,838	1,987	2,125	2,252	2,467	2,555

Notes:
Adjustment values presented here are reflected in all summer peak forecast values.

Table B-9

ADJUSTMENTS TO SUMMER PEAK LOAD (MW) FOR EACH PJM ZONE AND RTO
2022 - 2037

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
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	187	221	249	261	266	274	285	291	306	315	322	325	333	346	358	356
ATSI	66	109	132	148	165	174	181	186	191	191	191	191	190	192	194	192
COMED	-108	-141	-181	-220	-221	-224	-227	-231	-218	-221	-231	-220	-219	-222	-229	-219
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
OVEC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DOM	752	1,380	2,087	2,844	3,604	3,840	4,079	4,353	4,600	4,857	5,100	5,361	5,600	5,895	6,188	6,444
PJM RTO	897	1,643	2,344	3,061	3,885	4,166	4,441	4,624	4,834	5,118	5,505	5,754	6,002	6,297	6,588	6,798

Notes:
Adjustment values presented here are reflected in summer peak forecasts.
Adjustments are large, unanticipated changes deemed by PJM to not be captured in the load forecast model.

Table B-10

SUMMER COINCIDENT PEAK LOAD (MW) FOR
EACH PJM ZONE, LOCATIONAL DELIVERABILITY AREA AND RTO
2022 - 2037

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
AE	2,398	2,400	2,399	2,391	2,397	2,399	2,412	2,424	2,434	2,444	2,450	2,460	2,475	2,494	2,500	2,516
BGE	6,235	6,204	6,211	6,198	6,206	6,202	6,208	6,212	6,202	6,170	6,148	6,129	6,120	6,142	6,151	6,168
DPL	3,757	3,762	3,787	3,786	3,796	3,793	3,802	3,812	3,809	3,768	3,727	3,702	3,678	3,682	3,674	3,686
JCPL	5,654	5,622	5,585	5,595	5,620	5,596	5,606	5,631	5,655	5,687	5,699	5,722	5,739	5,793	5,819	5,869
METED	2,850	2,850	2,859	2,866	2,890	2,895	2,899	2,911	2,936	2,955	2,972	2,984	2,993	3,018	3,033	3,068
PECO	8,121	8,110	8,131	8,116	8,123	8,100	8,112	8,129	8,153	8,167	8,158	8,164	8,166	8,207	8,224	8,268
PENLC	2,717	2,708	2,708	2,712	2,720	2,710	2,711	2,708	2,726	2,740	2,740	2,741	2,737	2,740	2,762	2,775
PEPCO	5,744	5,726	5,734	5,741	5,735	5,721	5,692	5,683	5,650	5,629	5,594	5,562	5,517	5,526	5,528	5,544
PL	6,847	6,829	6,844	6,868	6,896	6,905	6,920	6,956	6,973	7,006	7,029	7,047	7,060	7,105	7,128	7,181
PS	9,279	9,273	9,264	9,258	9,328	9,288	9,324	9,384	9,435	9,507	9,499	9,540	9,603	9,713	9,743	9,834
RECO	377	376	374	373	373	372	372	373	373	373	373	373	373	375	376	377
UGI	187	186	186	185	186	185	185	185	184	184	184	184	183	184	183	184
AEP	21,525	21,544	21,659	21,656	21,686	21,662	21,689	21,728	21,738	21,751	21,723	21,752	21,748	21,869	21,877	21,962
APS	8,431	8,492	8,535	8,571	8,577	8,548	8,528	8,527	8,535	8,529	8,509	8,486	8,491	8,515	8,527	8,563
ATSI	11,885	11,927	12,014	12,039	12,107	12,097	12,080	12,136	12,155	12,144	12,135	12,137	12,103	12,166	12,163	12,199
COMED	20,119	19,955	19,827	19,702	19,668	19,623	19,572	19,590	19,537	19,498	19,447	19,423	19,334	19,386	19,350	19,359
DAYTON	3,145	3,140	3,149	3,149	3,159	3,150	3,152	3,153	3,159	3,161	3,153	3,153	3,152	3,166	3,175	3,187
DEOK	5,036	5,054	5,087	5,115	5,145	5,146	5,150	5,162	5,176	5,192	5,190	5,196	5,198	5,226	5,238	5,271
DLCO	2,641	2,654	2,678	2,692	2,707	2,710	2,709	2,719	2,720	2,728	2,725	2,722	2,716	2,729	2,736	2,747
EKPC	2,030	2,051	2,078	2,104	2,129	2,141	2,143	2,148	2,151	2,157	2,157	2,160	2,165	2,177	2,185	2,193
OVEC	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
DOM	19,890	20,418	21,128	21,977	22,743	23,008	23,352	23,692	24,001	24,414	24,697	25,060	25,356	25,854	26,259	26,669
PJM RTO	148,938	149,351	150,307	151,164	152,261	152,321	152,688	153,333	153,772	154,274	154,379	154,767	154,977	156,137	156,701	157,690
PJM MID-ATLANTIC	54,166	54,046	54,082	54,089	54,270	54,166	54,243	54,408	54,530	54,630	54,573	54,608	54,644	54,979	55,121	55,470
EASTERN MID-ATLANTIC	29,586	29,543	29,540	29,519	29,637	29,548	29,628	29,753	29,859	29,946	29,906	29,961	30,034	30,264	30,336	30,550
SOUTHERN MID-ATLANTIC	11,979	11,930	11,945	11,939	11,941	11,923	11,900	11,895	11,852	11,799	11,742	11,691	11,637	11,668	11,679	11,712

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, 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 2022
SUMMER TOTAL INTERNAL DEMAND FORECAST (MW) FOR EACH NERC REGION
2022 - 2037

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Annual Growth Rate (10 yr)
PJM - RELIABILITY FIRST												
TOTAL INTERNAL DEMAND	127,018	126,882	127,103	127,084	127,387	127,173	127,194	127,494	127,623	127,704	127,527	0.0%
% GROWTH TOTAL		-0.1%	0.2%	-0.0%	0.2%	-0.2%	0.0%	0.2%	0.1%	0.1%	-0.1%	
CONTRACTUALLY INTERRUPTIBLE	6,112	6,239	6,251	6,252	6,253	6,248	6,246	6,259	6,266	6,269	6,263	
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	6,112	6,239	6,251	6,252	6,253	6,248	6,246	6,259	6,266	6,269	6,263	
NET INTERNAL DEMAND	120,906	120,643	120,852	120,832	121,134	120,925	120,948	121,235	121,357	121,435	121,264	0.0%
% GROWTH NET		-0.2%	0.2%	-0.0%	0.2%	-0.2%	0.0%	0.2%	0.1%	0.1%	-0.1%	
PJM - SERC												
TOTAL INTERNAL DEMAND	21,920	22,469	23,206	24,081	24,872	25,149	25,495	25,840	26,152	26,571	26,854	2.1%
% GROWTH TOTAL		2.5%	3.3%	3.8%	3.3%	1.1%	1.4%	1.4%	1.2%	1.6%	1.1%	
CONTRACTUALLY INTERRUPTIBLE	805	826	853	881	908	919	930	941	953	966	977	
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	805	826	853	881	908	919	930	941	953	966	977	
NET INTERNAL DEMAND	21,115	21,643	22,353	23,200	23,964	24,230	24,565	24,899	25,199	25,605	25,877	2.1%
% GROWTH NET		2.5%	3.3%	3.8%	3.3%	1.1%	1.4%	1.4%	1.2%	1.6%	1.1%	
PJM RTO												
TOTAL INTERNAL DEMAND	148,938	149,351	150,309	151,165	152,259	152,322	152,689	153,334	153,775	154,275	154,381	0.4%
% GROWTH TOTAL		0.3%	0.6%	0.6%	0.7%	0.0%	0.2%	0.4%	0.3%	0.3%	0.1%	
CONTRACTUALLY INTERRUPTIBLE	6,917	7,065	7,104	7,133	7,161	7,167	7,176	7,200	7,219	7,235	7,240	
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	6,917	7,065	7,104	7,133	7,161	7,167	7,176	7,200	7,219	7,235	7,240	
NET INTERNAL DEMAND	142,021	142,286	143,205	144,032	145,098	145,155	145,513	146,134	146,556	147,040	147,141	0.4%
% GROWTH NET		0.2%	0.6%	0.6%	0.7%	0.0%	0.2%	0.4%	0.3%	0.3%	0.1%	

Notes:
SERC includes EKPC and DOM zones and Reliability First includes all other zones.
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 (2022).

Table B-11 (Continued)

PJM CONTROL AREA - JANUARY 2022
SUMMER TOTAL INTERNAL DEMAND FORECAST (MW) FOR EACH NERC REGION
2022 - 2037

	2033	2034	2035	2036	2037	Annual Growth Rate (15 yr)
PJM - RELIABILITY FIRST						
TOTAL INTERNAL DEMAND	127,547	127,456	128,104	128,256	128,827	0.1%
% GROWTH TOTAL	0.0%	-0.1%	0.5%	0.1%	0.4%	
CONTRACTUALLY INTERRUPTIBLE	6,263	6,259	6,272	6,288	6,304	
DIRECT CONTROL	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	6,263	6,259	6,272	6,288	6,304	
NET INTERNAL DEMAND	121,284	121,197	121,832	121,968	122,523	0.1%
% GROWTH NET	0.0%	-0.1%	0.5%	0.1%	0.5%	
PJM - SERC						
TOTAL INTERNAL DEMAND	27,220	27,521	28,031	28,444	28,862	1.9%
% GROWTH TOTAL	1.4%	1.1%	1.9%	1.5%	1.5%	
CONTRACTUALLY INTERRUPTIBLE	990	1,001	1,014	1,029	1,044	
DIRECT CONTROL	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	990	1,001	1,014	1,029	1,044	
NET INTERNAL DEMAND	26,230	26,520	27,017	27,415	27,818	1.9%
% GROWTH NET	1.4%	1.1%	1.9%	1.5%	1.5%	
PJM RTO						
TOTAL INTERNAL DEMAND	154,767	154,977	156,135	156,700	157,689	0.4%
% GROWTH TOTAL	0.3%	0.1%	0.7%	0.4%	0.6%	
CONTRACTUALLY INTERRUPTIBLE	7,253	7,260	7,286	7,317	7,348	
DIRECT CONTROL	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	7,253	7,260	7,286	7,317	7,348	
NET INTERNAL DEMAND	147,514	147,717	148,849	149,383	150,341	0.4%
% GROWTH NET	0.3%	0.1%	0.8%	0.4%	0.6%	

Notes:
SERC includes EKPC and DOM zones and Reliability First includes all other zones.
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 (2022).

Table B-12

PJM CONTROL AREA - JANUARY 2022
WINTER TOTAL INTERNAL DEMAND FORECAST (MW) FOR EACH NERC REGION
2021/22 - 2031/32

	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32	Annual Growth Rate (10 yr)
PJM - RELIABILITY FIRST												
TOTAL INTERNAL DEMAND	67,976	67,775	68,009	68,250	68,469	68,660	68,956	68,966	69,222	69,334	69,479	0.2%
% GROWTH TOTAL		-0.3%	0.3%	0.4%	0.3%	0.3%	0.4%	0.0%	0.4%	0.2%	0.2%	
CONTRACTUALLY INTERRUPTIBLE	5,550	5,550	5,560	5,561	5,562	5,558	5,558	5,569	5,578	5,583	5,581	
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	5,550	5,550	5,560	5,561	5,562	5,558	5,558	5,569	5,578	5,583	5,581	
NET INTERNAL DEMAND	62,426	62,225	62,449	62,689	62,907	63,102	63,398	63,397	63,644	63,751	63,898	0.2%
% GROWTH NET		-0.3%	0.4%	0.4%	0.3%	0.3%	0.5%	-0.0%	0.4%	0.2%	0.2%	
PJM - SERC												
TOTAL INTERNAL DEMAND	64,126	65,205	66,351	67,271	68,454	69,283	69,853	70,352	70,887	71,348	72,037	1.2%
% GROWTH TOTAL		1.7%	1.8%	1.4%	1.8%	1.2%	0.8%	0.7%	0.8%	0.7%	1.0%	
CONTRACTUALLY INTERRUPTIBLE	803	824	850	878	905	916	927	938	950	963	974	
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	803	824	850	878	905	916	927	938	950	963	974	
NET INTERNAL DEMAND	63,323	64,381	65,501	66,393	67,549	68,367	68,926	69,414	69,937	70,385	71,063	1.2%
% GROWTH NET		1.7%	1.7%	1.4%	1.7%	1.2%	0.8%	0.7%	0.8%	0.6%	1.0%	
PJM RTO												
TOTAL INTERNAL DEMAND	132,102	132,980	134,360	135,521	136,923	137,943	138,809	139,318	140,109	140,682	141,516	0.7%
% GROWTH TOTAL		0.7%	1.0%	0.9%	1.0%	0.7%	0.6%	0.4%	0.6%	0.4%	0.6%	
CONTRACTUALLY INTERRUPTIBLE	6,353	6,374	6,410	6,439	6,467	6,474	6,485	6,507	6,528	6,546	6,555	
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	6,353	6,374	6,410	6,439	6,467	6,474	6,485	6,507	6,528	6,546	6,555	
NET INTERNAL DEMAND	125,749	126,606	127,950	129,082	130,456	131,469	132,324	132,811	133,581	134,136	134,961	0.7%
% GROWTH NET		0.7%	1.1%	0.9%	1.1%	0.8%	0.7%	0.4%	0.6%	0.4%	0.6%	

Notes:
SERC includes EKPC and DOM zones and Reliability First includes all other zones.
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 (2022).

Table B-12 (Continued)

PJM CONTROL AREA - JANUARY 2022
WINTER TOTAL INTERNAL DEMAND FORECAST (MW) FOR EACH NERC REGION
2021/22 - 2031/32

	32/33	33/34	34/35	35/36	36/37	Annual Growth Rate (15 yr)
PJM - RELIABILITY FIRST						
TOTAL INTERNAL DEMAND	69,834	69,934	70,089	70,486	70,612	0.3%
% GROWTH TOTAL	0.5%	0.1%	0.2%	0.6%	0.2%	
CONTRACTUALLY INTERRUPTIBLE	5,583	5,583	5,596	5,610	5,624	
DIRECT CONTROL	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	5,583	5,583	5,596	5,610	5,624	
NET INTERNAL DEMAND	64,251	64,351	64,493	64,876	64,988	0.3%
% GROWTH NET	0.6%	0.2%	0.2%	0.6%	0.2%	
PJM - SERC						
TOTAL INTERNAL DEMAND	72,480	73,033	73,546	74,154	74,608	1.0%
% GROWTH TOTAL	0.6%	0.8%	0.7%	0.8%	0.6%	
CONTRACTUALLY INTERRUPTIBLE	987	998	1,011	1,026	1,041	
DIRECT CONTROL	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	987	998	1,011	1,026	1,041	
NET INTERNAL DEMAND	71,493	72,035	72,535	73,128	73,567	1.0%
% GROWTH NET	0.6%	0.8%	0.7%	0.8%	0.6%	
PJM RTO						
TOTAL INTERNAL DEMAND	142,314	142,967	143,635	144,640	145,220	0.6%
% GROWTH TOTAL	0.6%	0.5%	0.5%	0.7%	0.4%	
CONTRACTUALLY INTERRUPTIBLE	6,570	6,581	6,607	6,636	6,665	
DIRECT CONTROL	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	6,570	6,581	6,607	6,636	6,665	
NET INTERNAL DEMAND	135,744	136,386	137,028	138,004	138,555	0.6%
% GROWTH NET	0.6%	0.5%	0.5%	0.7%	0.4%	

Notes:
SERC includes EKPC and DOM zones and Reliability First includes all other zones.
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 (2022).

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
2022	18,220	22,261	18,658	21,101
2023	18,189	22,227	18,633	21,102
2024	18,216	22,239	18,629	21,204
2025	18,161	22,265	18,646	21,217
2026	18,179	22,283	18,683	21,259
2027	18,230	22,282	18,726	21,342
2028	18,290	22,306	18,726	21,529
2029	18,374	22,356	18,753	21,451
2030	18,383	22,345	18,778	21,615
2031	18,302	22,373	18,852	21,586
2032	18,452	22,369	18,912	21,656
2033	18,500	22,348	18,916	21,837
2034	18,531	22,314	18,923	21,877
2035	18,501	22,299	18,955	21,970
2036	18,424	22,373	19,147	22,071
2037	18,561	22,410	19,249	22,038

EXTREME WEATHER (90/10) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2022	20,085	23,706	20,221	23,012
2023	20,084	23,694	20,135	23,080
2024	19,946	23,702	20,021	23,168
2025	20,097	23,710	20,098	23,209
2026	20,207	23,702	20,081	23,287
2027	20,279	23,722	20,190	23,360
2028	20,136	23,749	20,177	23,462
2029	20,179	23,780	20,095	23,505
2030	20,231	23,772	20,137	23,488
2031	20,268	23,725	20,250	23,589
2032	20,441	23,707	20,323	23,671
2033	20,426	23,711	20,331	23,779
2034	20,444	23,749	20,337	23,831
2035	20,385	23,773	20,317	23,883
2036	20,357	23,790	20,441	23,963
2037	20,603	23,873	20,510	24,054

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, 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
2022	11,083	12,911	11,046	12,749
2023	11,056	12,874	11,024	12,727
2024	11,053	12,919	10,978	12,744
2025	11,029	12,965	10,981	12,726
2026	11,042	12,985	10,997	12,721
2027	11,064	13,018	11,049	12,760
2028	11,074	13,024	11,056	12,799
2029	11,095	13,072	11,081	12,820
2030	11,127	13,160	11,120	12,813
2031	11,118	13,227	11,176	12,833
2032	11,169	13,275	11,247	12,834
2033	11,183	13,308	11,265	12,896
2034	11,203	13,333	11,277	12,911
2035	11,227	13,367	11,302	12,924
2036	11,193	13,459	11,355	12,922
2037	11,236	13,518	11,411	12,918

EXTREME WEATHER (90/10) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2022	12,266	13,810	11,809	13,771
2023	12,226	13,774	11,798	13,761
2024	12,067	13,876	11,725	13,760
2025	11,967	13,893	11,772	13,737
2026	12,225	13,870	11,767	13,753
2027	12,322	13,893	11,814	13,786
2028	12,213	13,952	11,845	13,813
2029	12,234	14,014	11,827	13,834
2030	12,227	14,126	11,873	13,850
2031	12,029	14,187	11,992	13,836
2032	12,378	14,210	12,045	13,857
2033	12,308	14,261	12,082	13,909
2034	12,315	14,314	12,053	13,929
2035	12,270	14,373	12,081	13,933
2036	12,213	14,444	12,204	13,941
2037	12,344	14,518	12,260	13,930

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, 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
2022	21,524	30,333	24,325	22,211
2023	21,507	30,309	24,302	22,326
2024	21,518	30,275	24,257	22,422
2025	21,283	30,254	24,321	22,499
2026	21,159	30,298	24,337	22,617
2027	21,140	30,344	24,401	22,741
2028	21,503	30,470	24,470	22,886
2029	21,647	30,571	24,569	22,989
2030	21,746	30,642	24,734	23,135
2031	21,635	30,699	24,907	23,229
2032	21,568	30,742	25,049	23,387
2033	21,722	30,788	25,143	23,568
2034	21,925	30,881	25,254	23,704
2035	22,014	30,998	25,327	23,810
2036	22,111	31,092	25,584	24,009
2037	22,172	31,140	25,723	24,116

EXTREME WEATHER (90/10) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2022	24,148	32,524	26,619	23,455
2023	24,097	32,497	27,113	23,550
2024	24,035	32,503	27,192	23,638
2025	23,937	32,514	27,181	23,744
2026	23,814	32,570	26,571	23,864
2027	23,830	32,549	26,704	23,978
2028	24,037	32,668	27,404	24,138
2029	24,119	32,811	27,031	24,233
2030	24,170	32,918	27,723	24,404
2031	24,203	33,014	27,837	24,486
2032	24,244	33,080	27,603	24,649
2033	24,306	33,153	27,797	24,825
2034	24,413	33,277	28,115	24,970
2035	24,463	33,410	28,220	25,093
2036	24,518	33,620	28,360	25,294
2037	24,578	33,776	28,321	25,429

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, 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
2022	9,665	12,279	10,355	11,023
2023	9,669	12,260	10,334	11,103
2024	9,709	12,246	10,323	11,192
2025	9,665	12,259	10,358	11,207
2026	9,648	12,245	10,346	11,269
2027	9,661	12,235	10,366	11,322
2028	9,682	12,213	10,366	11,398
2029	9,700	12,206	10,332	11,429
2030	9,687	12,160	10,337	11,475
2031	9,671	12,116	10,336	11,466
2032	9,701	12,059	10,354	11,546
2033	9,743	11,997	10,347	11,609
2034	9,730	11,971	10,343	11,660
2035	9,760	12,004	10,364	11,722
2036	9,795	12,037	10,415	11,837
2037	9,881	12,050	10,471	11,889

EXTREME WEATHER (90/10) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2022	10,510	13,000	11,293	12,179
2023	10,536	12,970	11,276	12,268
2024	10,550	12,993	11,271	12,355
2025	10,524	12,973	11,275	12,414
2026	10,538	12,965	11,285	12,462
2027	10,593	12,973	11,306	12,511
2028	10,603	12,979	11,312	12,568
2029	10,630	12,973	11,188	12,612
2030	10,602	12,928	11,274	12,638
2031	10,605	12,898	11,273	12,680
2032	10,622	12,852	11,325	12,729
2033	10,616	12,826	11,316	12,783
2034	10,622	12,797	11,265	12,829
2035	10,622	12,810	11,253	12,886
2036	10,661	12,849	11,420	12,969
2037	10,773	12,868	11,461	13,035

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, 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 2022 - 2037

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
AE	2,691	2,693	2,692	2,695	2,698	2,713	2,724	2,739	2,748	2,756	2,771	2,780	2,794	2,804	2,820	2,838
BGE	6,868	6,854	6,871	6,872	6,865	6,875	6,887	6,899	6,901	6,923	6,942	6,959	6,957	6,949	6,937	6,943
DPL	4,192	4,197	4,193	4,203	4,212	4,223	4,238	4,245	4,247	4,220	4,208	4,178	4,163	4,149	4,141	4,167
JCPL	6,242	6,205	6,195	6,191	6,195	6,209	6,228	6,255	6,290	6,319	6,335	6,366	6,395	6,435	6,481	6,515
METED	3,264	3,271	3,259	3,272	3,297	3,301	3,342	3,332	3,358	3,383	3,404	3,450	3,470	3,460	3,498	3,525
PECO	9,370	9,385	9,341	9,337	9,355	9,350	9,424	9,391	9,412	9,437	9,461	9,543	9,559	9,550	9,544	9,636
PENLC	2,972	2,975	2,973	2,970	2,970	2,970	2,982	2,990	2,999	3,004	3,009	3,013	3,018	3,028	3,031	3,038
PEPCO	6,180	6,171	6,153	6,127	6,117	6,111	6,116	6,111	6,061	6,046	6,039	6,037	6,042	6,048	6,070	6,085
PL	7,499	7,511	7,557	7,556	7,561	7,570	7,608	7,644	7,699	7,732	7,729	7,800	7,798	7,835	7,909	7,930
PS	10,324	10,315	10,353	10,371	10,382	10,392	10,425	10,510	10,539	10,596	10,688	10,705	10,765	10,873	10,931	10,999
RECO	436	433	431	430	430	429	431	432	432	432	432	433	434	435	436	435
UGI	211	211	210	209	209	208	208	208	208	208	208	207	207	207	208	207
DIVERSITY - MID-ATLANTIC(-)	1,346	1,351	1,364	1,375	1,415	1,415	1,564	1,476	1,451	1,563	1,733	1,967	1,899	1,913	1,917	2,021
PJM MID-ATLANTIC	58,903	58,870	58,864	58,858	58,876	58,936	59,049	59,280	59,443	59,493	59,493	59,504	59,703	59,860	60,089	60,297
FE-EAST	12,267	12,235	12,217	12,251	12,216	12,251	12,290	12,353	12,431	12,487	12,521	12,601	12,601	12,677	12,737	12,778
PLGRP	7,709	7,712	7,752	7,752	7,768	7,769	7,803	7,845	7,903	7,939	7,929	8,000	7,993	8,036	8,109	8,125

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, 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
2022 - 2037

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
AEP	23,286	23,342	23,387	23,413	23,413	23,422	23,439	23,438	23,427	23,444	23,479	23,517	23,561	23,606	23,652	23,692
APS	9,230	9,268	9,318	9,352	9,368	9,342	9,342	9,340	9,358	9,371	9,381	9,398	9,416	9,408	9,466	9,490
ATSI	13,294	13,366	13,415	13,437	13,471	13,501	13,522	13,552	13,559	13,555	13,560	13,577	13,570	13,587	13,595	13,600
COMED	22,287	21,909	21,958	21,797	21,711	21,589	21,569	21,546	21,511	21,444	21,354	21,309	21,263	21,204	21,194	21,133
DAYTON	3,454	3,452	3,455	3,459	3,463	3,468	3,472	3,467	3,474	3,476	3,478	3,482	3,483	3,487	3,494	3,502
DEOK	5,541	5,570	5,603	5,628	5,644	5,659	5,685	5,696	5,705	5,713	5,716	5,729	5,744	5,759	5,776	5,789
DLCO	2,908	2,931	2,950	2,965	2,981	2,990	2,998	3,003	3,010	3,015	3,020	3,014	3,025	3,031	3,038	3,046
EKPC	2,250	2,280	2,306	2,330	2,355	2,368	2,374	2,378	2,383	2,387	2,393	2,398	2,408	2,415	2,418	2,430
OVEC	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
DIVERSITY - WESTERN(-)	2,368	2,183	2,060	2,048	2,292	2,375	2,131	2,116	2,133	2,224	2,520	2,260	2,295	2,255	2,407	2,399
PJM WESTERN	79,972	80,025	80,422	80,423	80,204	80,054	80,360	80,394	80,384	80,271	79,951	80,254	80,265	80,332	80,316	80,373
DOM	21,623	22,241	22,960	23,773	24,616	24,925	25,276	25,611	25,942	26,304	26,697	27,094	27,522	27,989	28,424	28,893
DIVERSITY - TOTAL(-)	7,284	6,977	6,692	6,711	7,064	7,427	7,103	6,952	6,968	7,265	7,618	7,932	7,918	8,036	8,140	8,579
PJM RTO	156,928	157,693	158,978	159,766	160,339	160,278	161,277	161,925	162,385	162,590	162,776	163,147	163,766	164,313	165,013	165,404

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, 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
2021/22 - 2036/37

	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32	32/33	33/34	34/35	35/36	36/37
AE	1,681	1,691	1,698	1,706	1,716	1,726	1,737	1,746	1,758	1,769	1,782	1,794	1,810	1,823	1,850	1,866
BGE	6,318	6,354	6,398	6,427	6,466	6,502	6,541	6,580	6,610	6,646	6,683	6,720	6,755	6,790	6,838	6,874
DPL	4,153	4,190	4,221	4,235	4,255	4,291	4,326	4,367	4,387	4,411	4,433	4,475	4,513	4,541	4,564	4,584
JCPL	3,852	3,863	3,881	3,897	3,923	3,951	3,980	4,005	4,034	4,060	4,093	4,126	4,159	4,186	4,236	4,269
METED	2,812	2,799	2,800	2,803	2,809	2,811	2,816	2,821	2,827	2,831	2,839	2,843	2,848	2,853	2,858	2,864
PECO	7,129	7,130	7,140	7,132	7,134	7,129	7,141	7,148	7,157	7,141	7,149	7,162	7,171	7,174	7,185	7,175
PENLC	2,964	2,956	2,960	2,954	2,932	2,925	2,947	2,951	2,950	2,944	2,923	2,941	2,939	2,942	2,938	2,913
PEPCO	5,870	5,918	5,962	5,987	5,997	6,009	6,037	6,035	6,029	6,034	6,046	6,073	6,074	6,098	6,139	6,162
PL	7,817	7,825	7,841	7,817	7,830	7,847	7,876	7,907	7,898	7,901	7,917	7,952	7,979	7,989	7,977	7,977
PS	6,856	6,900	6,956	7,000	7,061	7,114	7,170	7,230	7,290	7,354	7,426	7,490	7,557	7,632	7,725	7,821
RECO	234	235	235	236	237	239	240	241	243	244	245	247	249	250	253	254
UGI	211	210	210	209	208	208	207	207	206	206	205	205	205	205	204	203
DIVERSITY - MID-ATLANTIC(-)	701	725	726	787	636	661	711	731	829	811	659	733	764	794	817	783
PJM MID-ATLANTIC	49,196	49,346	49,576	49,616	49,932	50,091	50,307	50,507	50,560	50,730	51,082	51,295	51,495	51,689	51,950	52,179
FE-EAST	9,517	9,502	9,523	9,544	9,573	9,597	9,638	9,662	9,693	9,723	9,759	9,807	9,836	9,868	9,913	9,944
PLGRP	8,019	8,028	8,043	8,019	8,032	8,049	8,073	8,105	8,098	8,100	8,116	8,148	8,175	8,184	8,174	8,173

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, 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
2022 - 2037

	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32	32/33	33/34	34/35	35/36	36/37
AEP	24,019	24,074	24,192	24,290	24,312	24,399	24,452	24,506	24,494	24,584	24,577	24,669	24,713	24,754	24,751	24,793
APS	9,751	9,772	9,846	9,894	9,932	9,952	9,981	9,999	10,017	10,041	10,065	10,089	10,102	10,120	10,147	10,173
ATSI	10,591	10,621	10,683	10,688	10,697	10,687	10,694	10,696	10,689	10,680	10,669	10,670	10,669	10,672	10,658	10,635
COMED	15,856	15,844	15,862	15,856	15,904	15,955	16,006	16,045	16,085	16,112	16,161	16,221	16,251	16,313	16,378	16,411
DAYTON	3,119	3,113	3,124	3,121	3,132	3,135	3,142	3,143	3,133	3,136	3,147	3,157	3,157	3,166	3,162	3,178
DEOK	4,820	4,858	4,893	4,901	4,921	4,933	4,947	4,975	4,968	4,978	4,991	5,003	5,030	5,044	5,045	5,060
DLCO	2,092	2,099	2,111	2,114	2,117	2,120	2,126	2,131	2,130	2,132	2,135	2,140	2,142	2,143	2,145	2,147
EKPC	3,109	3,139	3,160	3,169	3,180	3,195	3,206	3,218	3,223	3,234	3,245	3,262	3,272	3,283	3,289	3,301
OVEC	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115
DIVERSITY - WESTERN(-)	1,635	1,637	1,643	1,636	1,584	1,638	1,628	1,620	1,588	1,646	1,559	1,608	1,598	1,618	1,590	1,572
PJM WESTERN	71,837	71,998	72,343	72,512	72,726	72,853	73,041	73,208	73,266	73,366	73,546	73,718	73,853	73,992	74,100	74,241
DOM	24,007	24,745	25,594	26,524	27,498	28,215	28,635	29,040	29,443	29,860	30,272	30,720	31,133	31,584	32,044	32,432
DIVERSITY - TOTAL(-)	4,598	4,669	4,787	4,649	4,597	4,656	4,646	4,879	5,035	4,786	4,653	4,679	4,883	5,006	5,136	4,947
PJM RTO	142,778	143,782	145,095	146,426	147,779	148,802	149,676	150,227	150,651	151,627	152,465	153,395	153,960	154,671	155,365	156,260

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, 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 2022 - 2032

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Annual Growth Rate (10 yr)
AE	9,440	9,411	9,398	9,341	9,333	9,376	9,484	9,551	9,645	9,752	9,897	0.5%
		-0.3%	-0.1%	-0.6%	-0.1%	0.5%	1.2%	0.7%	1.0%	1.1%	1.5%	
BGE	30,746	30,773	30,971	30,990	31,121	31,317	31,656	31,802	31,989	32,204	32,537	0.6%
		0.1%	0.6%	0.1%	0.4%	0.6%	1.1%	0.5%	0.6%	0.7%	1.0%	
DPL	18,356	18,374	18,425	18,384	18,401	18,466	18,619	18,668	18,723	18,748	18,830	0.3%
		0.1%	0.3%	-0.2%	0.1%	0.4%	0.8%	0.3%	0.3%	0.1%	0.4%	
JCPL	21,635	21,561	21,590	21,542	21,606	21,733	21,991	22,168	22,397	22,671	23,043	0.6%
		-0.3%	0.1%	-0.2%	0.3%	0.6%	1.2%	0.8%	1.0%	1.2%	1.6%	
METED	15,409	15,379	15,416	15,393	15,423	15,465	15,545	15,562	15,595	15,659	15,775	0.2%
		-0.2%	0.2%	-0.1%	0.2%	0.3%	0.5%	0.1%	0.2%	0.4%	0.7%	
PECO	39,254	39,266	39,281	39,076	38,988	38,969	39,117	39,071	39,095	39,172	39,376	0.0%
		0.0%	0.0%	-0.5%	-0.2%	-0.0%	0.4%	-0.1%	0.1%	0.2%	0.5%	
PENLC	16,802	16,745	16,737	16,646	16,619	16,615	16,674	16,652	16,654	16,686	16,768	(0.0%)
		-0.3%	-0.0%	-0.5%	-0.2%	-0.0%	0.4%	-0.1%	0.0%	0.2%	0.5%	
PEPCO	28,020	28,076	28,185	28,107	28,063	28,081	28,189	28,134	28,049	28,055	28,208	0.1%
		0.2%	0.4%	-0.3%	-0.2%	0.1%	0.4%	-0.2%	-0.3%	0.0%	0.5%	
PL	39,554	39,540	39,683	39,611	39,673	39,774	40,014	40,055	40,163	40,329	40,630	0.3%
		-0.0%	0.4%	-0.2%	0.2%	0.3%	0.6%	0.1%	0.3%	0.4%	0.7%	
PS	42,166	42,203	42,425	42,444	42,653	42,948	43,465	43,824	44,269	44,800	45,518	0.8%
		0.1%	0.5%	0.0%	0.5%	0.7%	1.2%	0.8%	1.0%	1.2%	1.6%	
RECO	1,402	1,395	1,388	1,379	1,377	1,379	1,394	1,399	1,408	1,424	1,440	0.3%
		-0.5%	-0.5%	-0.6%	-0.1%	0.1%	1.1%	0.4%	0.6%	1.1%	1.1%	
UGI	1,024	1,020	1,018	1,009	1,007	1,004	1,007	1,000	998	997	999	(0.2%)
		-0.4%	-0.2%	-0.9%	-0.2%	-0.3%	0.3%	-0.7%	-0.2%	-0.1%	0.2%	
PJM MID-ATLANTIC	263,808	263,743	264,517	263,922	264,264	265,127	267,155	267,886	268,985	270,497	273,021	0.3%
		-0.0%	0.3%	-0.2%	0.1%	0.3%	0.8%	0.3%	0.4%	0.6%	0.9%	
FE-EAST	53,846	53,685	53,743	53,581	53,648	53,813	54,210	54,382	54,646	55,016	55,586	0.3%
		-0.3%	0.1%	-0.3%	0.1%	0.3%	0.7%	0.3%	0.5%	0.7%	1.0%	
PLGRP	40,578	40,560	40,701	40,620	40,680	40,778	41,021	41,055	41,161	41,326	41,629	0.3%
		-0.0%	0.3%	-0.2%	0.1%	0.2%	0.6%	0.1%	0.3%	0.4%	0.7%	

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation, reductions for distributed battery storage, and additions for plug-in electric vehicles.
All average growth rates are calculated from the first year of the forecast (2022).

Table E-1 (continued)

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION 2033 - 2037

	2033	2034	2035	2036	2037	Annual Growth Rate (15 yr)
AE	9,984	10,114	10,256	10,476	10,598	0.8%
	0.9%	1.3%	1.4%	2.1%	1.2%	
BGE	32,684	32,955	33,288	33,917	34,231	0.7%
	0.5%	0.8%	1.0%	1.9%	0.9%	
DPL	18,805	18,850	18,932	19,103	19,151	0.3%
	-0.1%	0.2%	0.4%	0.9%	0.3%	
JCPL	23,263	23,582	23,944	24,492	24,816	0.9%
	1.0%	1.4%	1.5%	2.3%	1.3%	
METED	15,782	15,821	15,879	15,986	16,013	0.3%
	0.0%	0.2%	0.4%	0.7%	0.2%	
PECO	39,314	39,364	39,451	39,667	39,674	0.1%
	-0.2%	0.1%	0.2%	0.5%	0.0%	
PENLC	16,732	16,734	16,758	16,824	16,804	0.0%
	-0.2%	0.0%	0.1%	0.4%	-0.1%	
PEPCO	28,226	28,374	28,595	29,085	29,329	0.3%
	0.1%	0.5%	0.8%	1.7%	0.8%	
PL	40,633	40,742	40,889	41,172	41,211	0.3%
	0.0%	0.3%	0.4%	0.7%	0.1%	
PS	45,929	46,535	47,227	48,253	48,861	1.0%
	0.9%	1.3%	1.5%	2.2%	1.3%	
RECO	1,451	1,466	1,484	1,515	1,530	0.6%
	0.8%	1.0%	1.2%	2.1%	1.0%	
UGI	995	994	993	993	990	(0.2%)
	-0.4%	-0.1%	-0.1%	0.0%	-0.3%	
PJM MID-ATLANTIC	273,798	275,531	277,696	281,483	283,208	0.5%
	0.3%	0.6%	0.8%	1.4%	0.6%	
FE-EAST	55,777	56,137	56,581	57,302	57,633	0.5%
	0.3%	0.6%	0.8%	1.3%	0.6%	
PLGRP	41,628	41,736	41,882	42,165	42,201	0.3%
	-0.0%	0.3%	0.3%	0.7%	0.1%	

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation, reductions for distributed battery storage, and additions for plug-in electric vehicles.
All average growth rates are calculated from the first year of the forecast (2022).

Table E-1

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO 2022 - 2032

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Annual Growth Rate (10 yr)
AEP	127,782	128,128	128,860	128,815	129,004	129,299	130,055	130,085	130,190	130,645	131,491	0.3%
		0.3%	0.6%	-0.0%	0.1%	0.2%	0.6%	0.0%	0.1%	0.3%	0.6%	
APS	50,310	50,569	51,056	51,112	51,191	51,316	51,639	51,658	51,708	51,906	52,265	0.4%
		0.5%	1.0%	0.1%	0.2%	0.2%	0.6%	0.0%	0.1%	0.4%	0.7%	
ATSI	64,441	64,813	65,185	65,125	65,214	65,309	65,584	65,524	65,488	65,591	65,854	0.2%
		0.6%	0.6%	-0.1%	0.1%	0.1%	0.4%	-0.1%	-0.1%	0.2%	0.4%	
COMED	93,463	92,982	92,716	92,036	91,904	92,022	92,524	92,565	92,741	93,102	93,793	0.0%
		-0.5%	-0.3%	-0.7%	-0.1%	0.1%	0.5%	0.0%	0.2%	0.4%	0.7%	
DAYTON	16,829	16,809	16,843	16,804	16,800	16,811	16,878	16,871	16,847	16,884	16,964	0.1%
		-0.1%	0.2%	-0.2%	-0.0%	0.1%	0.4%	-0.0%	-0.1%	0.2%	0.5%	
DEOK	26,679	26,827	27,060	27,102	27,186	27,291	27,473	27,510	27,553	27,654	27,832	0.4%
		0.6%	0.9%	0.2%	0.3%	0.4%	0.7%	0.1%	0.2%	0.4%	0.6%	
DLCO	13,087	13,173	13,275	13,294	13,343	13,380	13,444	13,448	13,463	13,495	13,567	0.4%
		0.7%	0.8%	0.1%	0.4%	0.3%	0.5%	0.0%	0.1%	0.2%	0.5%	
EKPC	11,384	11,483	11,591	11,643	11,727	11,780	11,844	11,846	11,860	11,896	11,968	0.5%
		0.9%	0.9%	0.4%	0.7%	0.5%	0.5%	0.0%	0.1%	0.3%	0.6%	
OVEC	375	375	375	375	375	375	375	375	375	375	375	0.0%
		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
PJM WESTERN	404,350	405,159	406,961	406,306	406,744	407,583	409,816	409,882	410,225	411,548	414,109	0.2%
		0.2%	0.4%	-0.2%	0.1%	0.2%	0.5%	0.0%	0.1%	0.3%	0.6%	
DOM	113,160	118,859	125,595	132,352	139,354	142,817	146,136	148,623	151,408	154,427	158,003	3.4%
		5.0%	5.7%	5.4%	5.3%	2.5%	2.3%	1.7%	1.9%	2.0%	2.3%	
PJM RTO	781,318	787,761	797,073	802,580	810,362	815,527	823,107	826,391	830,618	836,472	845,133	0.8%
		0.8%	1.2%	0.7%	1.0%	0.6%	0.9%	0.4%	0.5%	0.7%	1.0%	

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation, reductions for distributed battery storage, and additions for plug-in electric vehicles.
All average growth rates are calculated from the first year of the forecast (2022).

Table E-1 (Continued)

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO 2022 - 2032

	2033	2034	2035	2036	2037	Annual Growth Rate (15 yr)
AEP	131,558	131,935	132,439	133,276	133,390	0.3%
	0.1%	0.3%	0.4%	0.6%	0.1%	
APS	52,298	52,476	52,713	53,138	53,244	0.4%
	0.1%	0.3%	0.5%	0.8%	0.2%	
ATSI	65,735	65,750	65,836	66,081	65,973	0.2%
	-0.2%	0.0%	0.1%	0.4%	-0.2%	
COMED	93,977	94,424	94,998	96,078	96,431	0.2%
	0.2%	0.5%	0.6%	1.1%	0.4%	
DAYTON	16,950	16,980	17,037	17,126	17,131	0.1%
	-0.1%	0.2%	0.3%	0.5%	0.0%	
DEOK	27,860	27,962	28,091	28,289	28,339	0.4%
	0.1%	0.4%	0.5%	0.7%	0.2%	
DLCO	13,545	13,556	13,585	13,665	13,672	0.3%
	-0.2%	0.1%	0.2%	0.6%	0.1%	
EKPC	11,971	12,002	12,042	12,103	12,108	0.4%
	0.0%	0.3%	0.3%	0.5%	0.0%	
OVEC	375	375	375	375	375	0.0%
	0.0%	0.0%	0.0%	0.0%	0.0%	
PJM WESTERN	414,269	415,460	417,116	420,131	420,663	0.3%
	0.0%	0.3%	0.4%	0.7%	0.1%	
DOM	160,628	163,762	166,999	170,984	173,715	2.9%
	1.7%	2.0%	2.0%	2.4%	1.6%	
PJM RTO	848,695	854,753	861,811	872,598	877,586	0.8%
	0.4%	0.7%	0.8%	1.3%	0.6%	

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation, reductions for distributed battery storage, and additions for plug-in electric vehicles.
All average growth rates are calculated from the first year of the forecast (2022).

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 2022	856	3,042	1,863	1,969	1,463	3,668	1,620	2,713	3,965	3,736	122	105	25,122
Feb 2022	741	2,606	1,593	1,711	1,293	3,192	1,445	2,349	3,482	3,264	106	94	21,876
Mar 2022	713	2,525	1,485	1,690	1,327	3,209	1,479	2,276	3,482	3,342	102	93	21,723
Apr 2022	606	2,082	1,210	1,420	1,117	2,745	1,271	1,861	2,873	2,873	93	74	18,225
May 2022	668	2,189	1,282	1,560	1,138	2,937	1,272	2,016	2,873	3,093	105	72	19,205
Jun 2022	825	2,596	1,539	1,891	1,263	3,357	1,324	2,415	3,113	3,680	132	78	22,213
Jul 2022	1,097	3,078	1,883	2,363	1,454	3,984	1,463	2,857	3,566	4,444	156	91	26,436
Aug 2022	1,012	2,889	1,752	2,184	1,426	3,837	1,434	2,714	3,421	4,277	146	85	25,177
Sep 2022	752	2,388	1,401	1,729	1,161	3,126	1,270	2,218	2,923	3,484	116	73	20,641
Oct 2022	650	2,172	1,269	1,543	1,151	2,800	1,310	1,990	2,921	3,134	100	74	19,114
Nov 2022	684	2,358	1,382	1,644	1,227	2,930	1,373	2,109	3,227	3,170	103	86	20,293
Dec 2022	836	2,821	1,697	1,931	1,389	3,469	1,541	2,502	3,708	3,669	121	99	23,783

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	MID-ATLANTIC
Jan 2023	862	3,062	1,877	1,977	1,458	3,676	1,617	2,741	3,970	3,764	122	105	25,231
Feb 2023	745	2,620	1,602	1,715	1,287	3,194	1,440	2,369	3,481	3,281	106	93	21,933
Mar 2023	710	2,528	1,483	1,682	1,323	3,208	1,470	2,285	3,482	3,344	101	93	21,709
Apr 2023	600	2,072	1,202	1,401	1,107	2,731	1,256	1,851	2,853	2,852	92	74	18,091
May 2023	663	2,184	1,282	1,556	1,140	2,945	1,269	2,017	2,879	3,101	105	72	19,213
Jun 2023	820	2,582	1,537	1,871	1,258	3,350	1,317	2,408	3,106	3,662	131	77	22,119
Jul 2023	1,092	3,069	1,882	2,342	1,449	3,979	1,456	2,852	3,559	4,426	155	90	26,351
Aug 2023	1,005	2,877	1,749	2,166	1,427	3,837	1,430	2,709	3,420	4,270	145	85	25,120
Sep 2023	744	2,380	1,396	1,714	1,152	3,123	1,262	2,208	2,906	3,472	115	72	20,544
Oct 2023	648	2,185	1,274	1,546	1,160	2,815	1,318	2,004	2,939	3,158	99	74	19,220
Nov 2023	684	2,375	1,386	1,654	1,233	2,942	1,375	2,121	3,240	3,187	103	86	20,386
Dec 2023	838	2,839	1,704	1,937	1,385	3,466	1,535	2,511	3,705	3,686	121	99	23,826

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	MID-ATLANTIC
Jan 2024	866	3,089	1,890	1,991	1,464	3,687	1,623	2,764	3,990	3,802	123	105	25,394
Feb 2024	775	2,733	1,668	1,785	1,334	3,314	1,493	2,465	3,616	3,427	110	96	22,816
Mar 2024	702	2,531	1,470	1,669	1,310	3,183	1,450	2,277	3,458	3,326	99	92	21,567
Apr 2024	599	2,093	1,204	1,406	1,123	2,745	1,267	1,864	2,891	2,885	92	74	18,243
May 2024	658	2,186	1,279	1,553	1,139	2,940	1,262	2,013	2,877	3,111	103	72	19,193
Jun 2024	811	2,565	1,528	1,845	1,243	3,312	1,297	2,387	3,079	3,620	128	76	21,891
Jul 2024	1,088	3,083	1,887	2,339	1,461	3,987	1,464	2,864	3,586	4,453	154	90	26,456
Aug 2024	996	2,867	1,741	2,147	1,421	3,811	1,417	2,695	3,406	4,253	143	84	24,981
Sep 2024	735	2,383	1,390	1,703	1,147	3,112	1,255	2,206	2,896	3,471	114	71	20,483
Oct 2024	646	2,202	1,278	1,552	1,167	2,811	1,322	2,013	2,957	3,184	99	74	19,305
Nov 2024	681	2,384	1,381	1,658	1,229	2,919	1,363	2,118	3,231	3,187	102	86	20,339
Dec 2024	841	2,855	1,709	1,942	1,378	3,460	1,524	2,519	3,696	3,706	121	98	23,849

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation, reductions for distributed battery storage, and additions for plug-in electric vehicles.

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	OVEC	PJM WESTERN	DOM	PJM RTO
Jan 2022	12,559	5,018	5,957	8,588	1,617	2,478	1,153	1,221	35	38,626	10,928	74,676
Feb 2022	10,831	4,389	5,299	7,502	1,402	2,139	1,023	995	35	33,615	9,302	64,793
Mar 2022	10,975	4,418	5,579	7,627	1,428	2,187	1,066	977	35	34,292	9,159	65,174
Apr 2022	9,266	3,692	4,736	6,678	1,175	1,874	937	779	25	29,162	7,944	55,331
May 2022	9,649	3,764	4,899	7,017	1,259	2,043	1,009	768	25	30,433	8,500	58,138
Jun 2022	10,362	3,981	5,361	8,075	1,411	2,315	1,147	910	25	33,587	9,440	65,240
Jul 2022	11,509	4,469	6,002	9,257	1,578	2,624	1,317	1,024	35	37,815	10,766	75,017
Aug 2022	11,369	4,382	5,870	9,006	1,564	2,548	1,246	1,001	30	37,016	10,432	72,625
Sep 2022	9,838	3,753	4,974	7,417	1,311	2,162	1,071	854	30	31,410	8,843	60,894
Oct 2022	9,505	3,698	4,912	6,892	1,247	1,927	989	792	30	29,992	8,397	57,503
Nov 2022	10,228	4,020	5,168	7,154	1,325	2,020	1,011	958	35	31,919	8,945	61,157
Dec 2022	11,691	4,726	5,684	8,250	1,512	2,362	1,118	1,105	35	36,483	10,504	70,770

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	OVEC	WESTERN	DOM	PJM RTO
Jan 2023	12,589	5,038	5,983	8,591	1,616	2,492	1,157	1,229	35	38,730	11,443	75,404
Feb 2023	10,857	4,406	5,321	7,496	1,401	2,152	1,026	1,001	35	33,695	9,758	65,386
Mar 2023	10,999	4,436	5,616	7,601	1,427	2,199	1,072	988	35	34,373	9,635	65,717
Apr 2023	9,219	3,688	4,726	6,596	1,160	1,874	938	787	25	29,013	8,379	55,483
May 2023	9,682	3,787	4,947	6,994	1,259	2,054	1,017	773	25	30,538	8,977	58,728
Jun 2023	10,358	3,992	5,388	8,000	1,405	2,321	1,154	917	25	33,560	9,864	65,543
Jul 2023	11,517	4,486	6,022	9,159	1,574	2,636	1,325	1,034	35	37,788	11,222	75,361
Aug 2023	11,398	4,402	5,907	8,945	1,562	2,561	1,255	1,011	30	37,071	10,893	73,084
Sep 2023	9,861	3,767	4,990	7,335	1,305	2,171	1,079	862	30	31,400	9,271	61,215
Oct 2023	9,597	3,741	4,981	6,893	1,255	1,948	1,004	800	30	30,249	8,906	58,375
Nov 2023	10,315	4,055	5,228	7,148	1,333	2,042	1,024	971	35	32,151	9,460	61,997
Dec 2023	11,736	4,771	5,704	8,224	1,512	2,377	1,122	1,110	35	36,591	11,051	71,468

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	OVEC	WESTERN	DOM	PJM RTO
Jan 2024	12,702	5,104	6,044	8,623	1,628	2,520	1,168	1,237	35	39,061	12,028	76,483
Feb 2024	11,318	4,610	5,550	7,770	1,456	2,249	1,070	1,040	35	35,098	10,649	68,563
Mar 2024	10,974	4,445	5,592	7,506	1,414	2,199	1,071	993	35	34,229	10,137	65,933
Apr 2024	9,344	3,760	4,802	6,630	1,175	1,905	951	800	25	29,392	8,933	56,568
May 2024	9,711	3,820	4,962	6,944	1,257	2,066	1,022	773	25	30,580	9,498	59,271
Jun 2024	10,283	3,981	5,342	7,850	1,387	2,315	1,150	921	25	33,254	10,319	65,464
Jul 2024	11,620	4,539	6,079	9,142	1,588	2,668	1,339	1,046	35	38,056	11,776	76,288
Aug 2024	11,383	4,409	5,893	8,837	1,552	2,567	1,257	1,018	30	36,946	11,391	73,318
Sep 2024	9,871	3,782	4,995	7,256	1,303	2,183	1,085	872	30	31,377	9,765	61,625
Oct 2024	9,651	3,776	5,026	6,886	1,260	1,966	1,015	808	30	30,418	9,465	59,188
Nov 2024	10,305	4,058	5,230	7,084	1,324	2,046	1,027	979	35	32,088	9,986	62,413
Dec 2024	11,698	4,772	5,670	8,188	1,499	2,376	1,120	1,104	35	36,462	11,648	71,959

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation, reductions for distributed battery storage, and additions for plug-in electric vehicles.

Table E-3

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

	FE_EAST	PLGRP
Jan 2022	5,052	4,070
Feb 2022	4,449	3,576
Mar 2022	4,496	3,575
Apr 2022	3,808	2,947
May 2022	3,970	2,945
Jun 2022	4,478	3,191
Jul 2022	5,280	3,657
Aug 2022	5,044	3,506
Sep 2022	4,160	2,996
Oct 2022	4,004	2,995
Nov 2022	4,244	3,313
Dec 2022	4,861	3,807

	FE_EAST	PLGRP
Jan 2023	5,052	4,075
Feb 2023	4,442	3,574
Mar 2023	4,475	3,575
Apr 2023	3,764	2,927
May 2023	3,965	2,951
Jun 2023	4,446	3,183
Jul 2023	5,247	3,649
Aug 2023	5,023	3,505
Sep 2023	4,128	2,978
Oct 2023	4,024	3,013
Nov 2023	4,262	3,326
Dec 2023	4,857	3,804

	FE_EAST	PLGRP
Jan 2024	5,078	4,095
Feb 2024	4,612	3,712
Mar 2024	4,429	3,550
Apr 2024	3,796	2,965
May 2024	3,954	2,949
Jun 2024	4,385	3,155
Jul 2024	5,264	3,676
Aug 2024	4,985	3,490
Sep 2024	4,105	2,967
Oct 2024	4,041	3,031
Nov 2024	4,250	3,317
Dec 2024	4,844	3,794

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation, reductions for distributed battery storage, and additions for plug-in electric vehicles.

Table E-4

PLUG IN ELECTRIC VEHICLE ADJUSTMENT TO ANNUAL ENERGY (GWh) FOR EACH PJM ZONE AND RTO
2022 - 2037

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
AE	80	116	154	199	258	322	391	462	541	628	725	825	933	1,054	1,231	1,360
BGE	223	327	438	571	745	932	1,135	1,344	1,579	1,835	2,121	2,414	2,734	3,090	3,610	3,990
DPL	71	94	119	150	190	234	280	328	382	440	504	570	641	721	839	924
JCPL	187	272	361	468	607	756	918	1,084	1,271	1,475	1,703	1,937	2,192	2,476	2,892	3,194
METED	30	34	38	43	50	57	64	71	79	87	97	106	116	128	146	158
PECO	83	94	105	119	136	155	174	193	215	238	264	290	318	349	398	431
PENLC	29	32	36	41	47	53	60	67	74	82	91	100	110	120	137	149
PEPCO	186	273	366	477	622	779	948	1,124	1,321	1,536	1,776	2,023	2,292	2,593	3,032	3,354
PL	72	81	90	102	118	133	150	167	186	206	228	250	274	302	344	372
PS	312	452	601	779	1,010	1,259	1,528	1,805	2,116	2,455	2,834	3,224	3,649	4,122	4,813	5,316
RECO	13	18	24	31	41	51	61	72	85	99	114	130	147	166	193	214
UGI	2	2	2	3	3	4	4	4	5	6	6	7	7	8	9	10
AEP	163	192	235	323	425	530	638	746	862	983	1,112	1,239	1,372	1,516	1,731	1,871
APS	98	128	162	210	270	334	402	471	548	630	721	812	911	1,020	1,182	1,296
ATSI	96	108	121	136	156	177	198	220	244	269	297	325	356	390	443	479
COMED	419	607	806	1,045	1,357	1,692	2,053	2,424	2,839	3,290	3,792	4,306	4,863	5,480	6,383	7,033
DAYTON	26	29	33	37	42	48	54	59	66	73	80	88	96	105	120	129
DEOK	38	43	48	55	62	71	79	88	97	108	119	130	142	156	177	192
DLCO	27	30	34	39	44	50	57	63	70	77	86	94	103	113	129	140
EKPC	10	11	12	14	16	18	20	22	25	28	31	34	37	41	46	50
DOM	251	332	492	886	1,329	1,783	2,251	2,715	3,209	3,720	4,259	4,782	5,325	5,903	6,754	7,300
PJM RTO	2,414	3,276	4,277	5,729	7,529	9,436	11,465	13,529	15,814	18,264	20,960	23,686	26,618	29,853	34,612	37,962

Notes:
Adjustment values presented here are reflected in all energy forecast values.

Table F-1

PJM RTO HISTORICAL PEAKS
(MW)

SUMMER

YEAR	NORMALIZED BASE	NORMALIZED COOLING	NORMALIZED TOTAL	UNRESTRICTED PEAK	PEAK DATE	TIME
1998				133,275	Tuesday, July 21, 1998	17:00
1999				141,491	Friday, July 30, 1999	17:00
2000				131,798	Wednesday, August 9, 2000	17:00
2001				150,924	Thursday, August 9, 2001	16:00
2002				150,826	Thursday, August 1, 2002	17:00
2003				145,227	Thursday, August 21, 2003	17:00
2004				139,279	Tuesday, August 3, 2004	17:00
2005	95,846	60,592	156,438	155,257	Tuesday, July 26, 2005	16:00
2006	95,311	62,441	157,751	166,929	Wednesday, August 2, 2006	17:00
2007	96,738	64,277	161,015	162,035	Wednesday, August 8, 2007	16:00
2008	97,213	64,812	162,025	150,622	Monday, June 9, 2008	17:00
2009	94,732	62,518	157,251	145,112	Monday, August 10, 2009	16:00
2010	93,191	64,317	157,508	157,247	Wednesday, July 7, 2010	17:00
2011	93,397	62,808	156,205	165,524	Thursday, July 21, 2011	17:00
2012	93,024	61,796	154,821	158,219	Tuesday, July 17, 2012	17:00
2013	92,558	60,591	153,149	159,149	Thursday, July 18, 2013	17:00
2014	91,934	61,359	153,293	141,509	Tuesday, June 17, 2014	18:00
2015	91,214	60,419	151,632	143,579	Tuesday, July 28, 2015	17:00
2016	89,900	60,934	150,834	152,069	Thursday, August 11, 2016	16:00
2017	88,999	61,077	150,076	145,434	Wednesday, July 19, 2017	18:00
2018	89,895	59,766	149,660	150,573	Tuesday, August 28, 2018	17:00
2019	89,624	59,511	149,135	151,302	Friday, July 19, 2019	18:00
2020	85,951	59,866	145,817	144,320	Monday, July 20, 2020	17:00
2021	85,327	62,602	147,929	148,433	Tuesday, August 24, 2021	18:00

Notes:
Normalized values for 2000 - 2021 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-1

PJM RTO HISTORICAL PEAKS
(MW)

WINTER

YEAR	NORMALIZED BASE	NORMALIZED HEATING	NORMALIZED TOTAL	UNRESTRICTED PEAK	PEAK DATE	TIME
97/98				103,231	Wednesday, January 14, 1998	19:00
98/99				116,086	Tuesday, January 5, 1999	19:00
99/00				118,435	Thursday, January 27, 2000	20:00
00/01				118,046	Wednesday, December 20, 2000	19:00
01/02				112,217	Wednesday, January 2, 2002	19:00
02/03				129,965	Thursday, January 23, 2003	19:00
03/04				122,424	Friday, January 23, 2004	9:00
04/05			128,151	131,234	Monday, December 20, 2004	19:00
05/06	94,721	33,935	128,655	126,777	Wednesday, December 14, 2005	19:00
06/07	96,152	34,170	130,322	136,804	Monday, February 5, 2007	20:00
07/08	97,256	34,273	131,529	128,368	Wednesday, January 2, 2008	19:00
08/09	96,416	30,280	126,696	134,077	Friday, January 16, 2009	19:00
09/10	93,507	34,737	128,244	125,350	Monday, January 4, 2010	19:00
10/11	91,898	37,451	129,350	132,315	Tuesday, December 14, 2010	19:00
11/12	92,373	37,430	129,804	124,506	Tuesday, January 3, 2012	19:00
12/13	92,158	37,172	129,330	128,810	Tuesday, January 22, 2013	19:00
13/14	91,242	37,993	129,234	141,866	Tuesday, January 7, 2014	19:00
14/15	90,287	39,971	130,258	142,856	Friday, February 20, 2015	8:00
15/16	89,758	41,029	130,787	129,540	Tuesday, January 19, 2016	8:00
16/17	89,231	41,513	130,744	130,825	Thursday, December 15, 2016	19:00
17/18	89,243	41,915	131,158	137,212	Friday, January 5, 2018	19:00
18/19	88,372	41,892	130,265	137,618	Thursday, January 31, 2019	8:00
19/20	86,032	42,177	128,209	120,272	Thursday, December 19, 2019	8:00
20/21	85,341	44,664	130,005	117,012	Friday, January 29, 2021	9:00

Notes:
Normalized values for 2000 - 2021 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	718,248	2.4%
1999	740,056	3.0%
2000	756,211	2.2%
2001	754,516	-0.2%
2002	782,275	3.7%
2003	780,666	-0.2%
2004	796,702	2.1%
2005	823,342	3.3%
2006	802,984	-2.5%
2007	836,241	4.1%
2008	822,608	-1.6%
2009	781,270	-5.0%
2010	820,038	5.0%
2011	805,911	-1.7%
2012	791,768	-1.8%
2013	795,098	0.4%
2014	796,228	0.1%
2015	791,580	-0.6%
2016	791,176	-0.1%
2017	772,291	-2.4%
2018	804,917	4.2%
2019	785,209	-2.4%
2020	755,241	-3.8%

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

Table F-3

WEATHER NORMALIZED LOAD (MW) FOR
EACH PJM ZONE, LOCATIONAL DELIVERABILITY AREA AND RTO

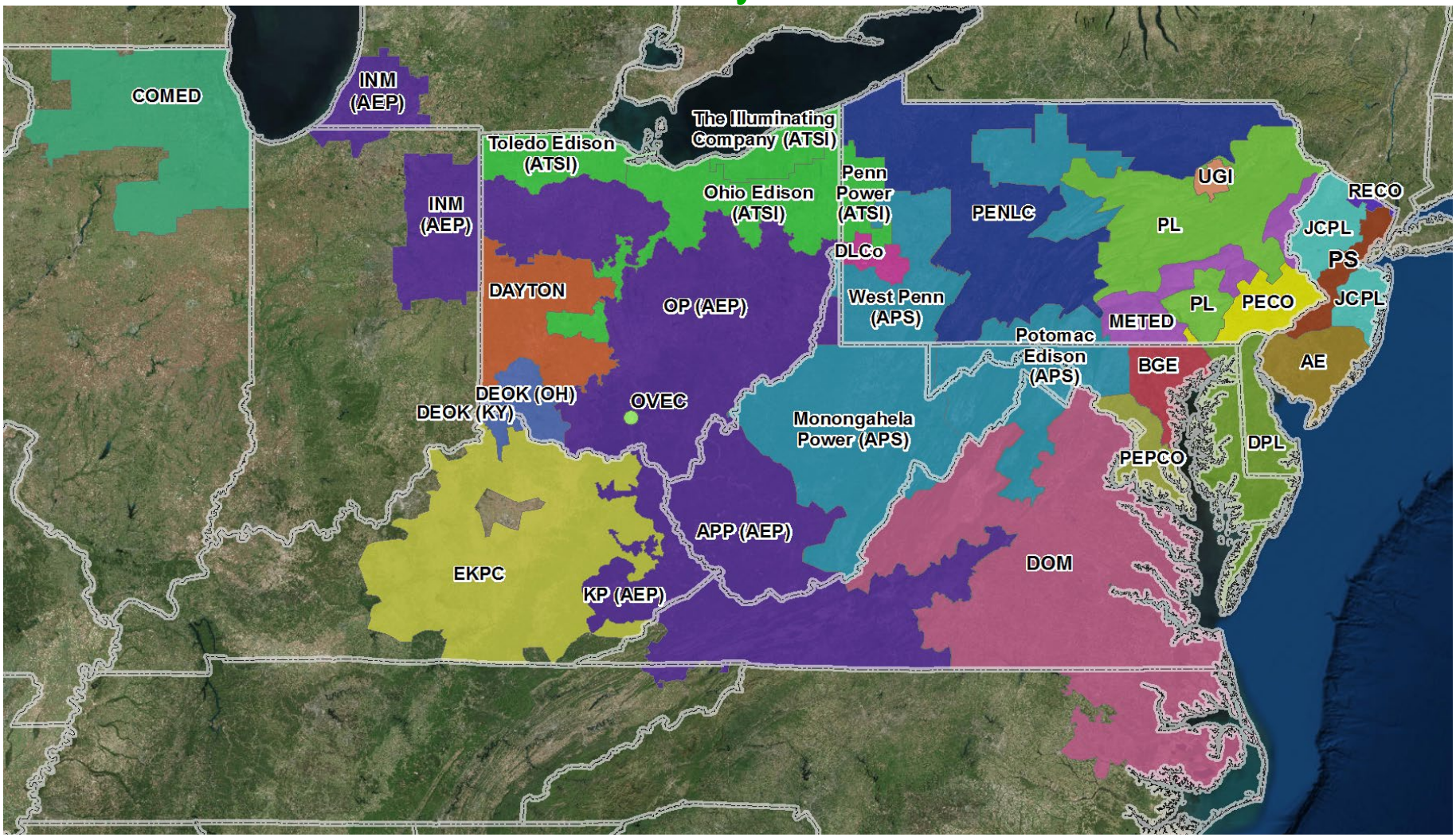
	Summer 2021	Winter 2020/21
AE	2,484	1,603
BGE	6,431	5,819
DPL	3,874	3,598
JCPL	5,864	3,698
METED	2,945	2,617
PECO	8,346	6,501
PENLC	2,816	2,807
PEPCO	5,843	5,257
PL	7,025	7,242
PS	9,521	6,607
RECO	390	220
UGI	195	203
AEP	22,045	22,042
APS	8,621	8,870
ATSI	12,240	10,116
COMED	20,809	14,726
DAYTON	3,273	2,943
DEOK	5,190	4,484
DLCO	2,731	1,978
EKPC	2,058	2,643
OVEC	90	115
DOM	19,803	19,736
PJM MID-ATLANTIC	55,122	45,503
PJM WESTERN	75,369	66,572
PJM RTO	147,929	130,005

Notes:
Zonal Normal 2021 are non-coincident as estimated by PJM staff.
Locational Deliverability Area and PJM RTO Normal 2021 are coincident with their regional peak as estimated by PJM staff.

EXHIBIT NO. 48

PJM Load Forecast Report

January 2023



Prepared by PJM Resource Adequacy Planning Department

TABLE OF CONTENTS

	TABLE NUMBER	CHART PAGE	TABLE PAGE
EXECUTIVE SUMMARY			1
FORECAST COMPARISON:			
Each Zone and PJM RTO – Comparison to Prior Summer Peak Forecasts	A-1		29
Each Zone and PJM RTO – Comparison to Prior Winter Peak Forecasts	A-2		31
PEAK LOAD FORECAST AND ANNUAL GROWTH RATES:			
Summer Peak Forecasts and Growth Rates of each Zone, Geographic Region and PJM RTO	B-1	3-28	33
Winter Peak Forecasts and Growth Rates of each Zone, Geographic Region and PJM RTO	B-2	3-28	37
Spring Peak Forecasts of each Zone, Geographic Region and PJM RTO	B-3		41
Fall Peak Forecasts of each Zone, Geographic Region and PJM RTO	B-4		43
Monthly Peak Forecasts of each Zone, Geographic Region and PJM RTO	B-5		45
Monthly Peak Forecasts of FE-East and PLGrp	B-6		47
Load Management Placed Under PJM Coordination by Zone, used in Planning	B-7		48
Distributed Solar Adjustments to Summer Peak Forecasts	B-8a		54
Plug-In Electric Vehicle Adjustments to Summer Peak Forecasts	B-8b		55
Adjustments above Embedded to Summer Peak Forecasts	B-9		56
Summer Coincident Peak Load Forecasts of each Zone, Locational Deliverability Area and PJM RTO (RPM Forecast)	B-10		57

	TABLE NUMBER	CHART PAGE	TABLE PAGE
Seasonal Unrestricted PJM Control Area Peak Forecasts of each NERC Region	B-11,B-12		58
LOCATIONAL DELIVERABILITY AREA SEASONAL PEAKS:			
Central Mid-Atlantic: BGE, MetEd, PEPCO, PL and UGI Seasonal Peaks	C-1		62
Western Mid-Atlantic: MetEd, PENLC, PL and UGI Seasonal Peaks	C-2		63
Eastern Mid-Atlantic: AE, DPL, JCPL, PECO, PS and RECO Seasonal Peaks	C-3		64
Southern Mid-Atlantic: BGE and PEPCO Seasonal Peaks	C-4		65
EXTREME WEATHER (90/10) PEAK LOAD FORECASTS:			
Summer 90/10 Peak Forecasts of each Zone, Geographic Region and PJM RTO	D-1		66
Winter 90/10 Peak Forecasts of each Zone, Geographic Region and PJM RTO	D-2		68
NET ENERGY FORECAST AND ANNUAL GROWTH RATES:			
Annual Net Energy Forecasts of each Zone, Geographic Region and PJM RTO	E-1		70
Monthly Net Energy Forecasts of each Zone, Geographic Region and PJM RTO	E-2		74
Monthly Net Energy Forecasts of FE-East and PLGrp	E-3		76
Annual Plug-In Vehicle Net Energy Forecasts of each Zone, Geographic Region and PJM RTO	E-4		77

	TABLE NUMBER	CHART PAGE	TABLE PAGE
PJM HISTORICAL DATA:			
Historical RTO Summer and Winter Peaks	F-1		78
Historical RTO Net Energy for Load	F-2		80
Weather-Normalized Seasonal Peaks of each Zone, Geographic Region and PJM RTO	F-3		81

TERMS AND ABBREVIATIONS USED IN THIS REPORT

AE	Atlantic Electric zone
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)
Battery Storage	(Also Battery Energy Storage System – BESS) Devices that enable generated energy to be stored and then released at a later time
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
EKPC	East Kentucky Power Cooperative zone (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
OVEC	Ohio Valley Electric Corporation zone (incorporated 12/1/2018)
PECO	PECO Energy zone
PED	Potomac Edison, sub-zone of APS
PEPCO	Potomac Electric Power zone
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
PRD	Price Responsive Demand
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 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

2023 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, distributed solar generation, plug-in electric vehicles, and battery storage for each PJM zone, region, locational deliverability area (LDA), and the total RTO.

- In 2022, PJM engaged with an outside consultant Itron to help with its transition to an hourly forecast model. Itron's report was shared with the Load Analysis Subcommittee and can be found here (https://www.pjm.com/-/media/committees-groups/subcommittees/las/2022/20220912/pjm-model-review-final-report-from-itron.ashx).

- Residential, Commercial, and Industrial sector models were estimated with data from 2012 through 2021. Weather scenarios were simulated with data from years 1993 through 2021, generating 377 scenarios.

- The economic forecast used was Moody's Analytics' September 2022 release.

- The 2022 update of Itron's end-use data provides the basis for appliance saturation rates, efficiency, and intensity and is consistent with the Energy Information Administration's 2022 Annual Energy Outlook. PJM obtained additional information from certain zones on Residential saturation rates based on their own load research. Details on zones providing information are presented in the supplement.

- The forecasts of the following zones have been adjusted to account for large, unanticipated load changes, market adjustments, and peak shaving adjusments(see Table B-9 and the supplement for details):
  - The AEP forecast of the AEP zone has been adjusted to account to account for growth in data center load;
  - The APS forecast has been adjusted to account to account for growth in data center load;
  - The DOM forecast has been adjusted to account for growth in data center load
  - The EKPC forecast has been adjusted to account for a peak shaving program to commence with the 2023 DY.
  - The AEP, APS, and PL forecasts have been adjusted to account for Non-Retail Behind-the-Meter Generation (NRBTMG) transitioning to participation as Demand Response in the

Reliability Pricing Model.

- Summer peak load growth for the PJM RTO is projected to average 0.8% per year over the next 10 and 15 years. The PJM RTO summer peak is forecasted to be 160,971 MW in 2033, a 10-year increase of 11,912 MW, and reaches 167,567 MW in 2038, a 15-year increase of 18,507 MW. Annualized 10-year growth rates for individual zones range from -0.7% to 5%; median of -0.1%.

- Winter peak load growth for PJM RTO is projected to average 1% per year over the next 10-year period, and 0.9% over the next 15-years. The PJM RTO winter peak load in 2032/33 is forecasted to be 144,992 MW, a 10-year increase of 14,180 MW, and reaches 150,555 MW in 2037/38, a 15-year increase of 19,744 MW. Annualized 10-year growth rates for individual zones range from -0.3% to 4.8%; median of 0.1%.

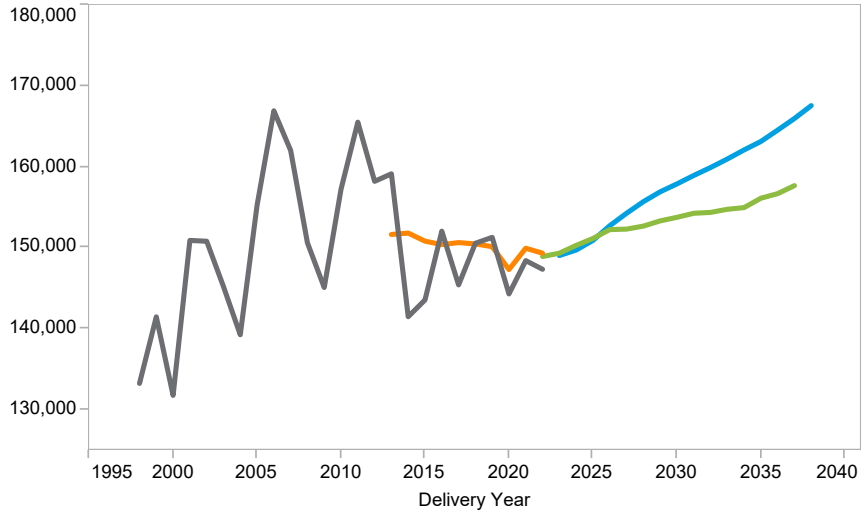
- Net energy for load growth for PJM RTO is projected to average 1.4% per year over the next 10-year period, and 1.3% over the next 15-years. Total PJM RTO energy is forecasted to be 909,622 GWh in 2033, a 10-year increase of 121,572 GWh, and reaches 960,428 GWh in 2038, a 15-year increase of 172,378 GWh. Annualized 10- year growth rates for individual zones range from -0.7% to 7%; median of 0%.

- Compared to the 2022 Load Report, the 2023 PJM RTO summer peak forecast shows the following changes for three years of interest:
  - The next delivery year – 2023 -293 MW (-0.2%)
  - The next RPM auction year – 2026 +473 MW (+0.3%)
  - The next RTEP study year – 2028 +3,015 MW (+2%)

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 battery storage, additions for plug-in electric vehicles, and prior to reductions for load management impacts.
All compound growth rates are calculated from the first year of the forecast.

PJM RTO

Summer Peak



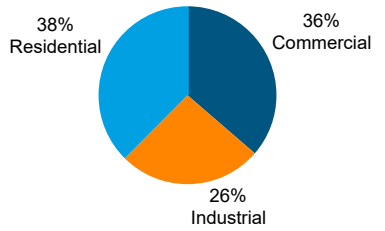
Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*74.3*
Avg Summer Max Temp	*95.1*
Avg Winter Daily Temp	*34.2*
Avg Winter Min Temp	*4.0*

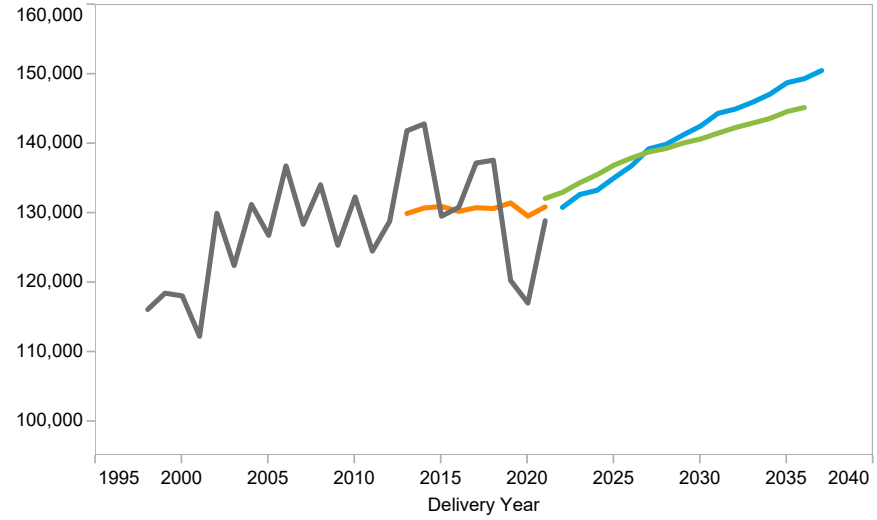
Zonal 10/15 Year Load Growth

SUMMER	0.8%	0.8%
WINTER	1.0%	0.9%

RCI Makeup



Winter Peak



LDAs

PJM Mid-Atlantic	Central MAAC
Eastern MAAC	Western MAAC
Southern MAAC	PJM West

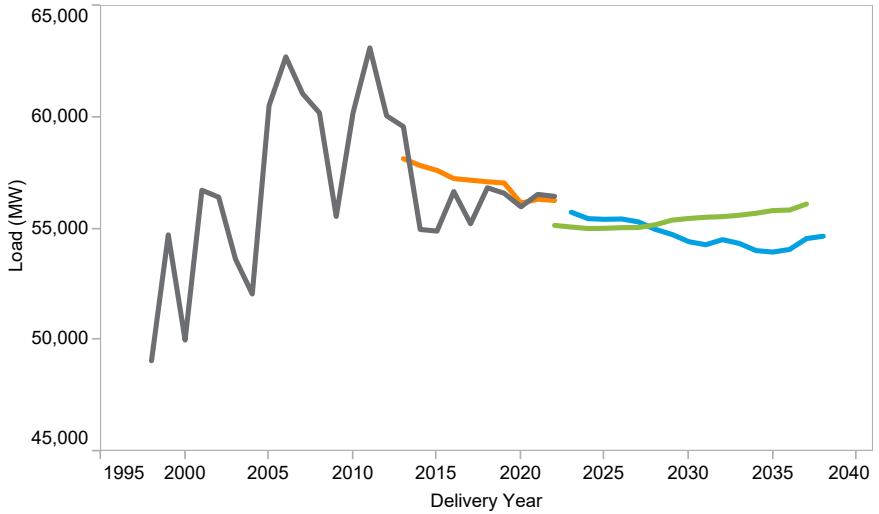
Zones

AE	DAYTON	JCPL	PEPCO
AEP	DEOK	METED	PL
APS	DLCO	OVEC	PS
ATSI	DOM	PECO	RECO
BGE	DPL	PENLC	UGI
COMED	EKPC		

Peak WN peak Forecast 2022 Forecast 2023

PJM Mid-Atlantic (MAAC)

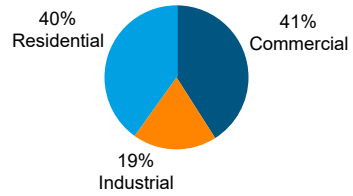
Summer Peak



Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*75.3*
Avg Summer Max Temp	*96.9*
Avg Winter Daily Temp	*35.4*
Avg Winter Min Temp	*7.4*

RCI Makeup



Zonal 10/15 Year Load Growth

SUMMER	-0.3%	-0.1%
WINTER	0.1%	0.0%

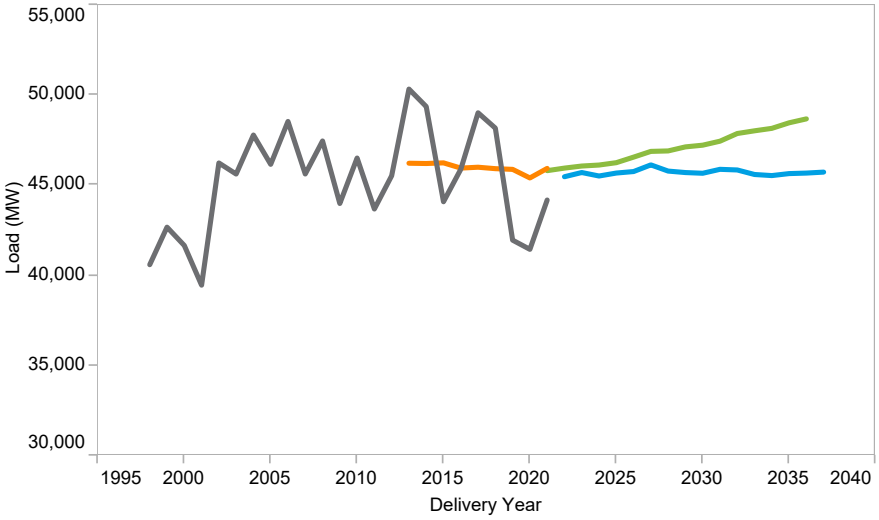
Zones

AE	JCPL	PENLC	PSEG
BGE	METED	PEPCO	RECO
DPL	PECO	PL	UGI

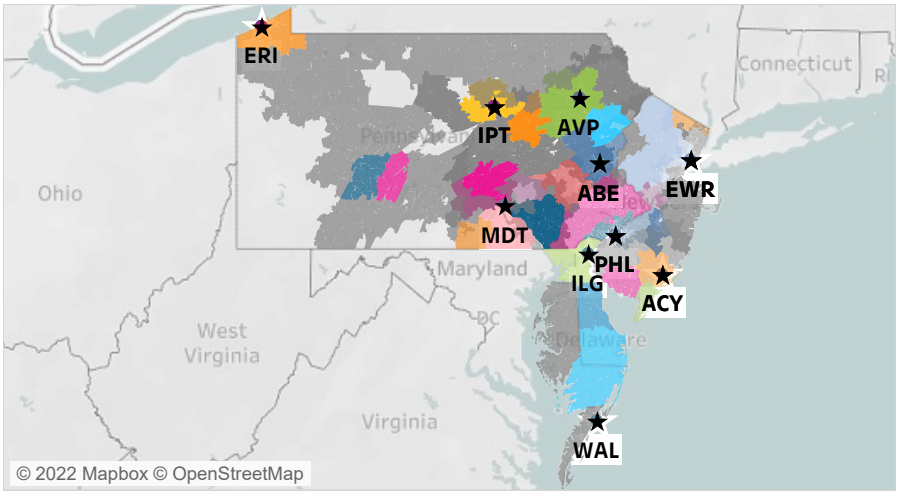
LDAs

E-MAAC	C-MAAC
S-MAAC	W-MAAC

Winter Peak



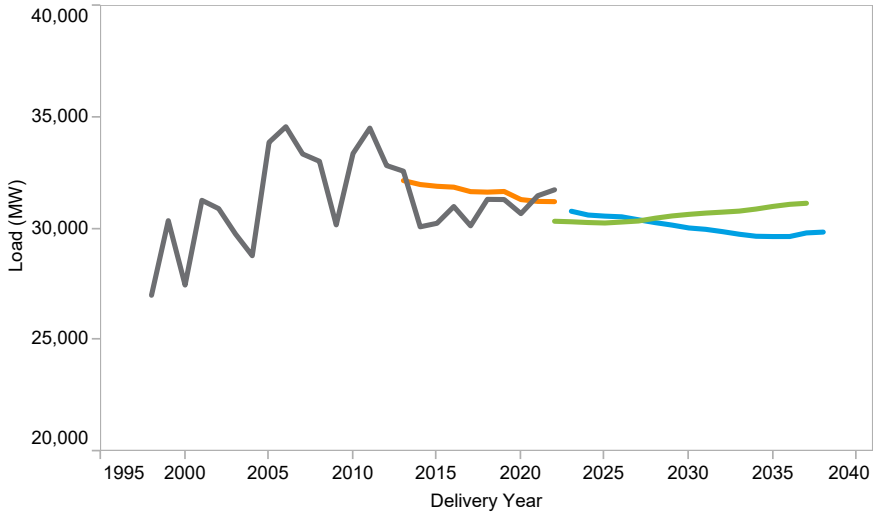
Metropolitan Statistical Areas and Weather Stations



Peak WN peak Forecast 2022 Forecast 2023

PJM Eastern Mid-Atlantic (E-MAAC)

Summer Peak



Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*75.8*
Avg Summer Max Temp	*97.7*
Avg Winter Daily Temp	*36.2*
Avg Winter Min Temp	*8.3*

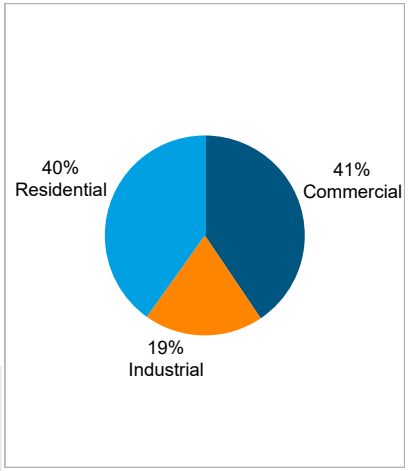
Zonal 10/15 Year Load Growth

SUMMER	-0.3%	-0.2%
WINTER	0.1%	0.0%

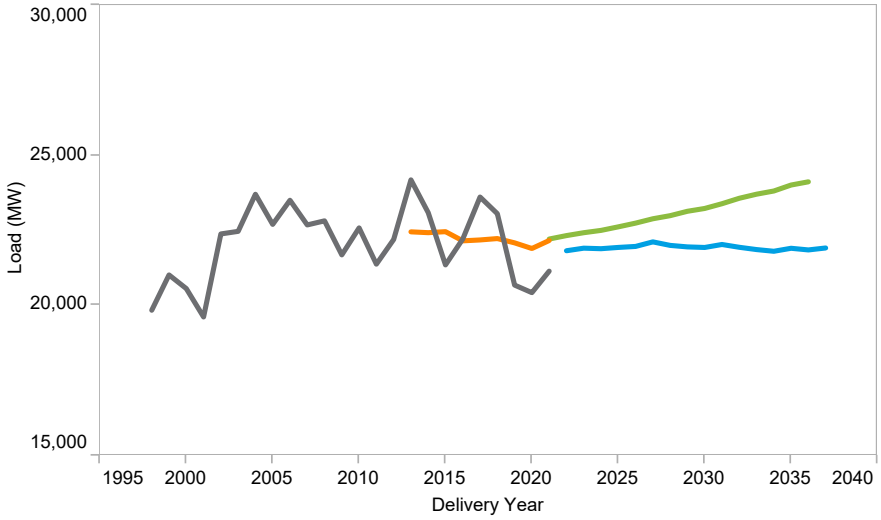
Zones

AE	PECO
DPL	PS
JCPL	RECO

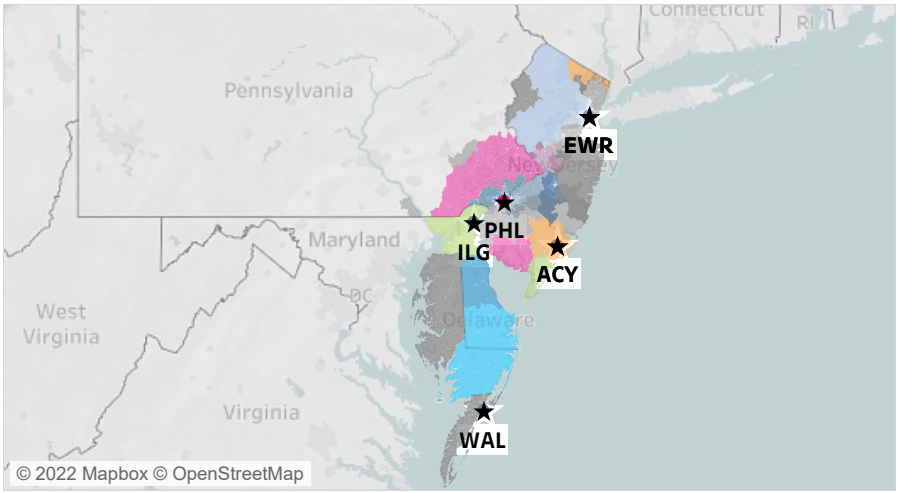
RCI Makeup



Winter Peak



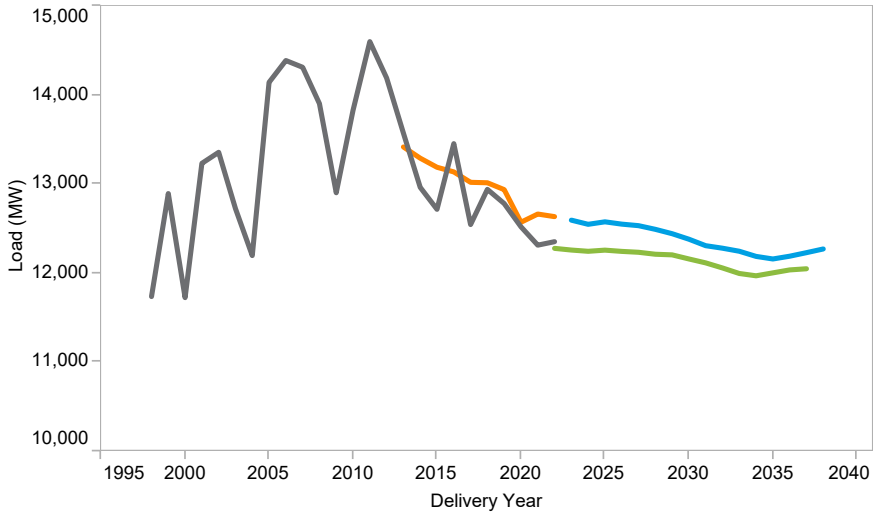
Metropolitan Statistical Areas and Weather Stations



Peak WN peak Forecast 2022 Forecast 2023

PJM Southern Mid-Atlantic (S-MAAC)

Summer Peak



Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*77.0*
Avg Summer Max Temp	*98.1*
Avg Winter Daily Temp	*37.8*
Avg Winter Min Temp	*10.2*

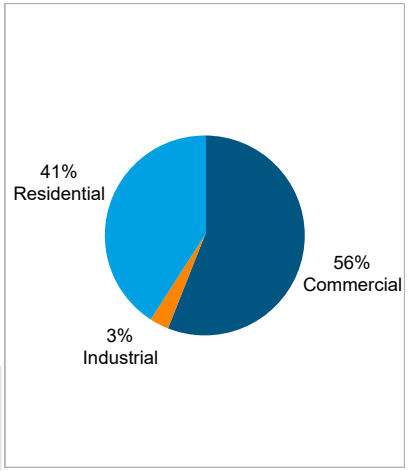
Zonal 10/15 Year Load Growth

SUMMER	-0.3%	-0.2%
WINTER	0.1%	0.1%

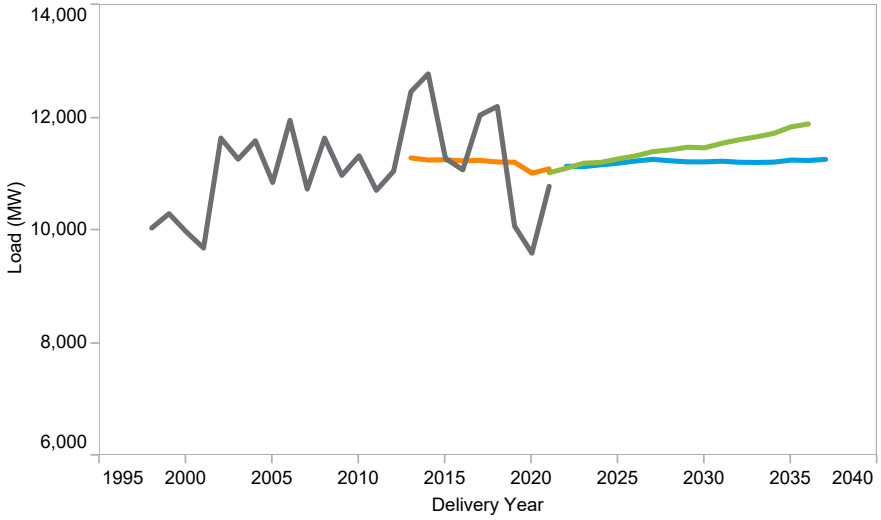
Zones

BGE PEPCO

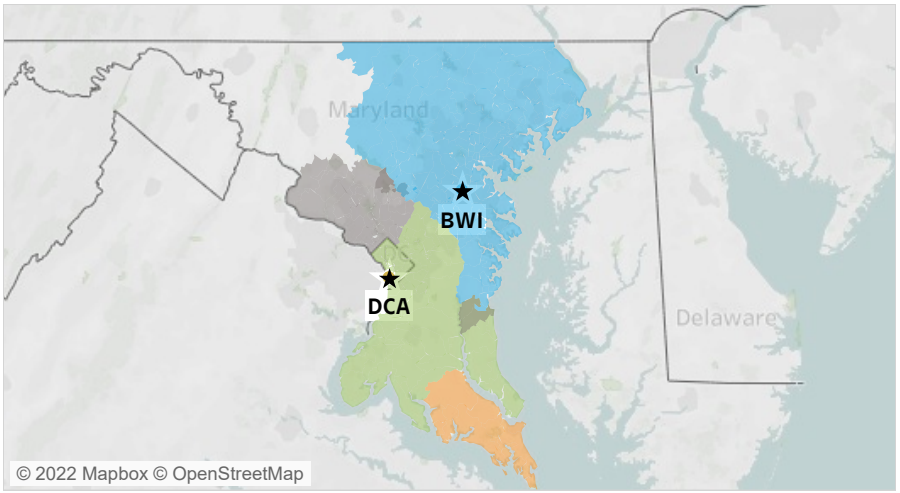
RCI Makeup



Winter Peak



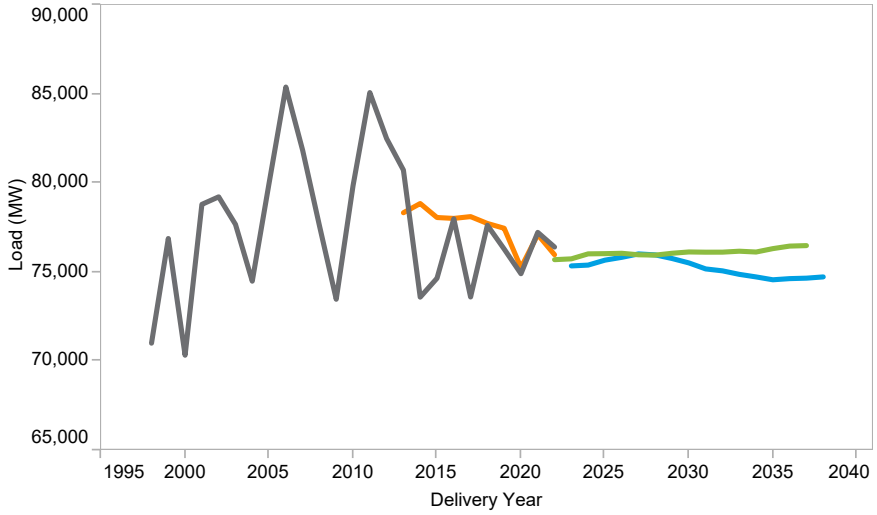
Metropolitan Statistical Areas and Weather Stations



Peak WN peak Forecast 2022 Forecast 2023

PJM Western

Summer Peak



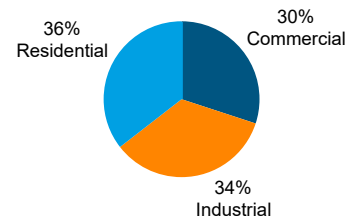
Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*72.9*
Avg Summer Max Temp	*93.3*
Avg Winter Daily Temp	*31.5*
Avg Winter Min Temp	*-0.8*

Zonal 10/15 Year Load Growth

SUMMER	-0.1%	-0.1%
WINTER	0.2%	0.1%

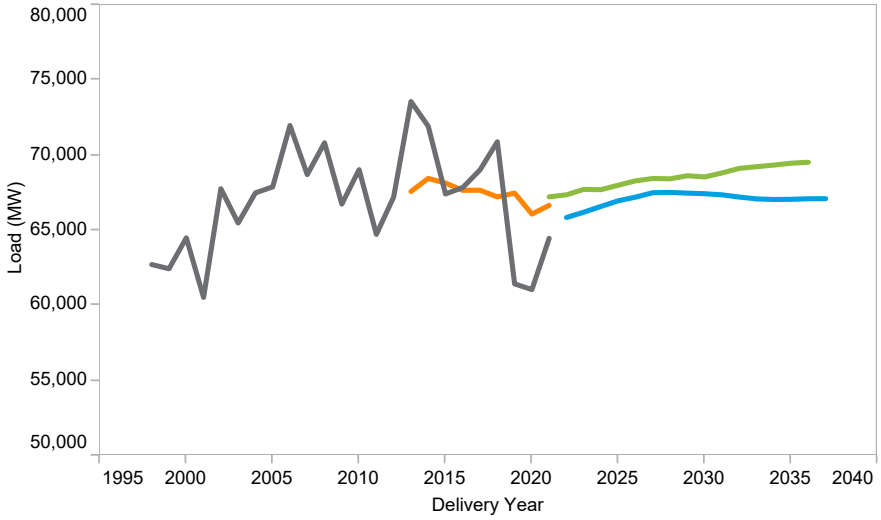
RCI Makeup



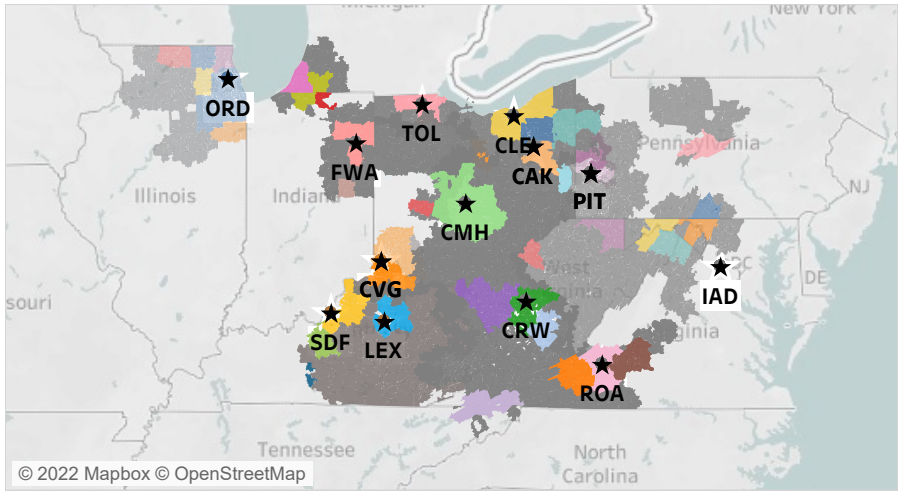
Zones

AEP	COMED	DLCO
APS	DAYTON	EKPC
ATSI	DEOK	OVEC

Winter Peak



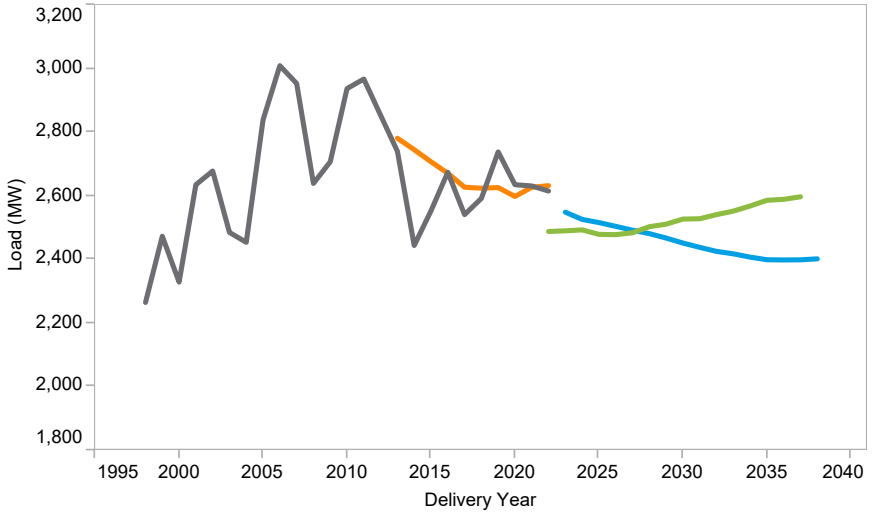
Metropolitan Statistical Areas and Weather Stations



Peak WN peak Forecast 2022 Forecast 2023

Atlantic Electric (AE)

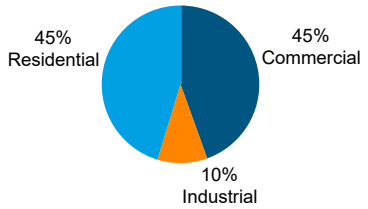
Summer Peak



Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*74.3*
Avg Summer Max Temp	*97.1*
Avg Winter Daily Temp	*36.6*
Avg Winter Min Temp	*5.9*

RCI Makeup



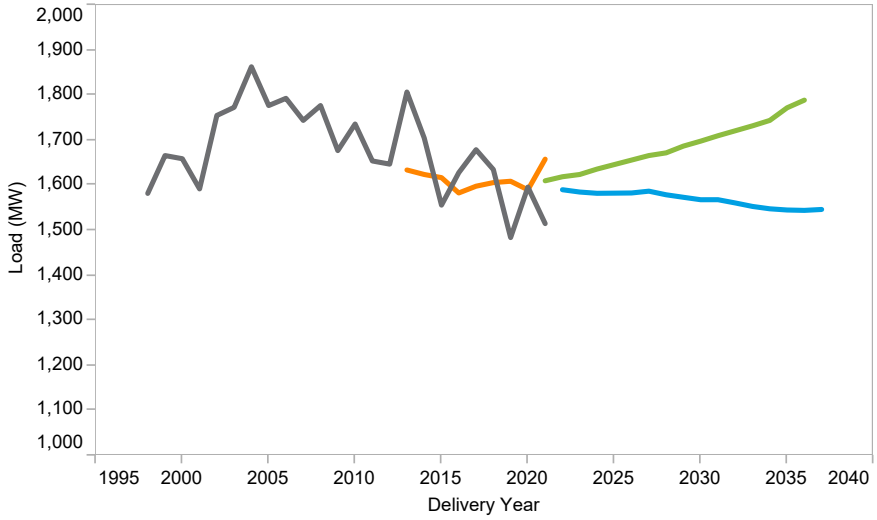
Zonal 10/15 Year Load Growth

SUMMER	-0.5%	-0.4%
WINTER	-0.2%	-0.2%

LDAs

EASTERN MID-ATLANTIC PJM MID-ATLANTIC PJM RTO

Winter Peak



Peak WN peak Forecast 2022 Forecast 2023

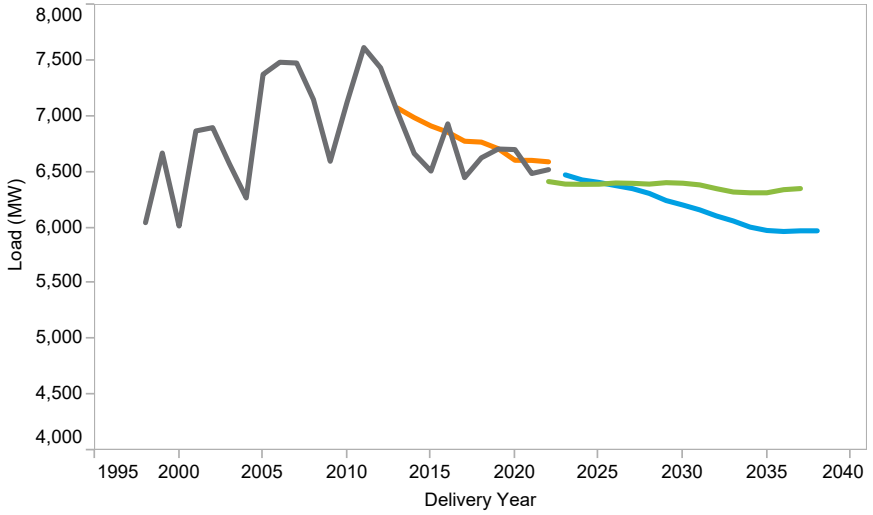
Metropolitan Statistical Areas and Weather Stations



AE - Non-Metro
Atlantic City-Hammonton, NJ
Ocean City, NJ
Vineland-Bridgeton, NJ

Baltimore Gas and Electric (BGE)

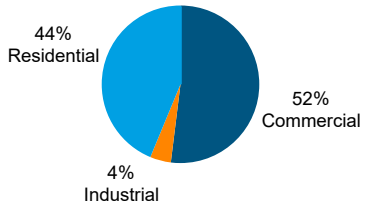
Summer Peak



Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*76.0*
Avg Summer Max Temp	*98.1*
Avg Winter Daily Temp	*36.7*
Avg Winter Min Temp	*7.9*

RCI Makeup



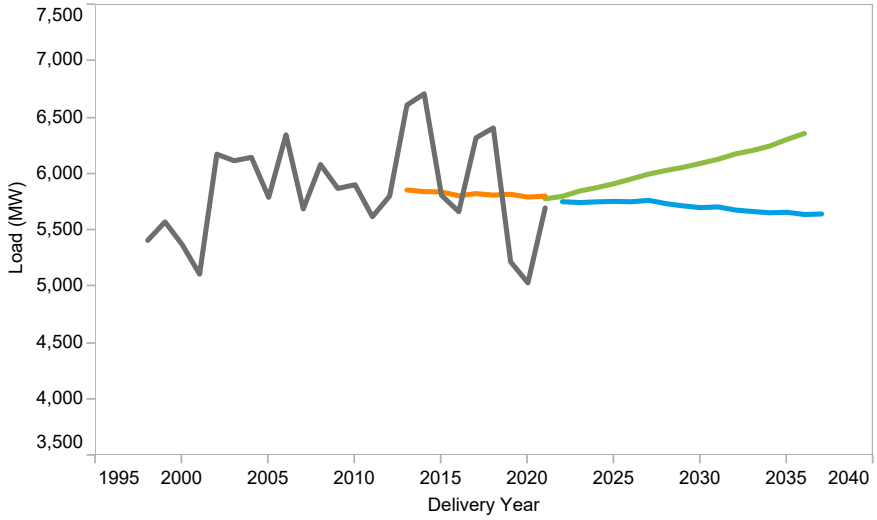
Zonal 10/15 Year Load Growth

SUMMER	-0.7%	-0.5%
WINTER	-0.1%	-0.1%

LDAs

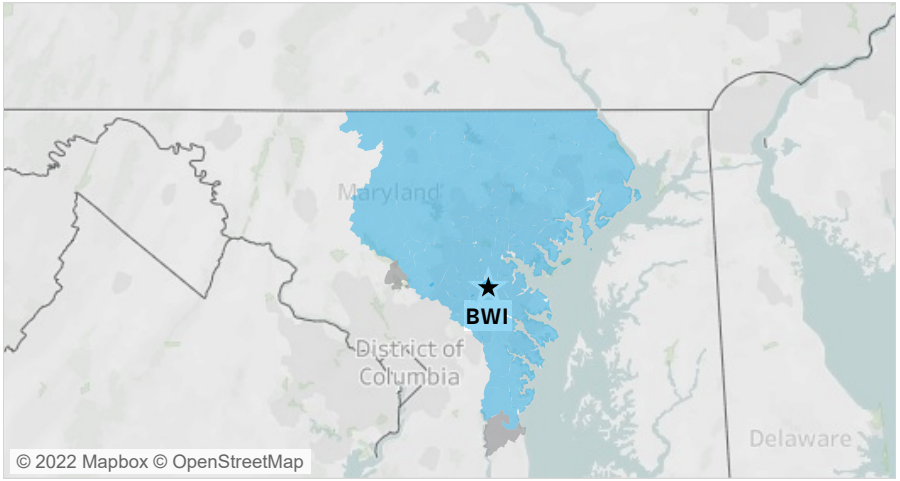
CENTRAL MID-ATLANTIC PJM MID-ATLANTIC PJM RTO
SOUTHERN MID-ATLANTIC

Winter Peak



Peak WN peak Forecast 2022 Forecast 2023

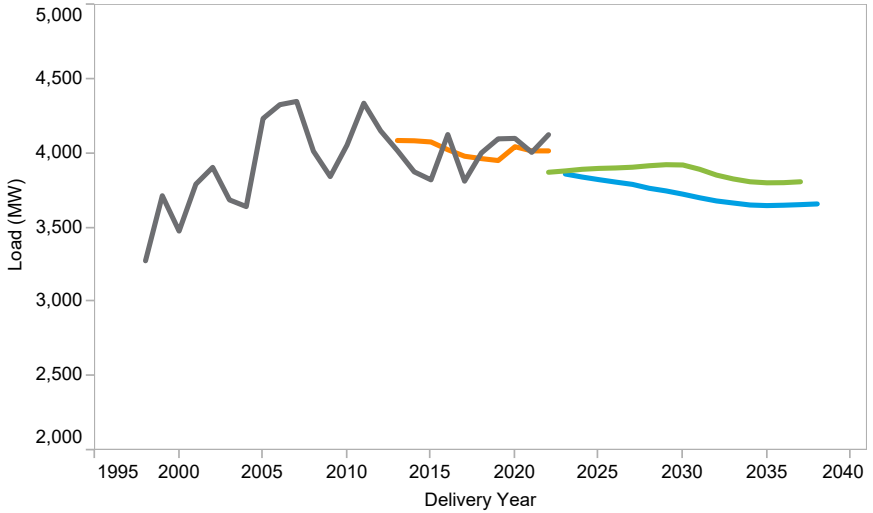
Metropolitan Statistical Areas and Weather Stations



Baltimore-Columbia-Towson, MD
BGE - Non-Metro

Delmarva Power and Light (DPL)

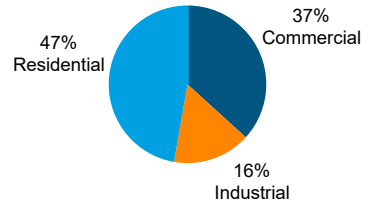
Summer Peak



Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*75.5*
Avg Summer Max Temp	*95.1*
Avg Winter Daily Temp	*37.0*
Avg Winter Min Temp	*9.7*

RCI Makeup



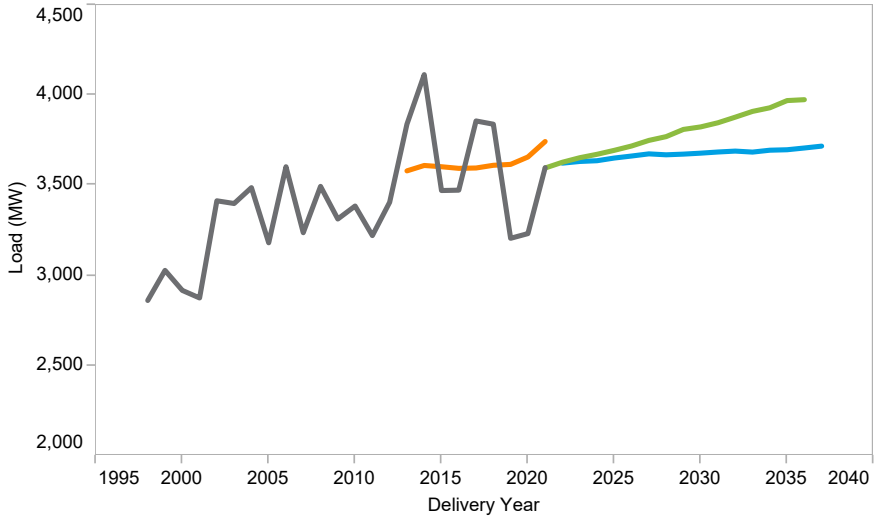
Zonal 10/15 Year Load Growth

SUMMER	-0.5%	-0.4%
WINTER	0.2%	0.2%

LDAs

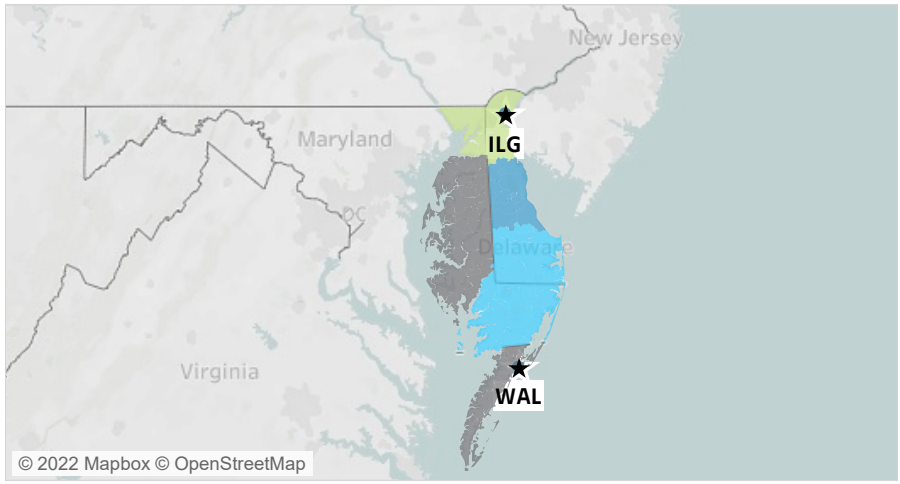
EASTERN MID-ATLANTIC PJM MID-ATLANTIC PJM RTO

Winter Peak



Peak WN peak Forecast 2022 Forecast 2023

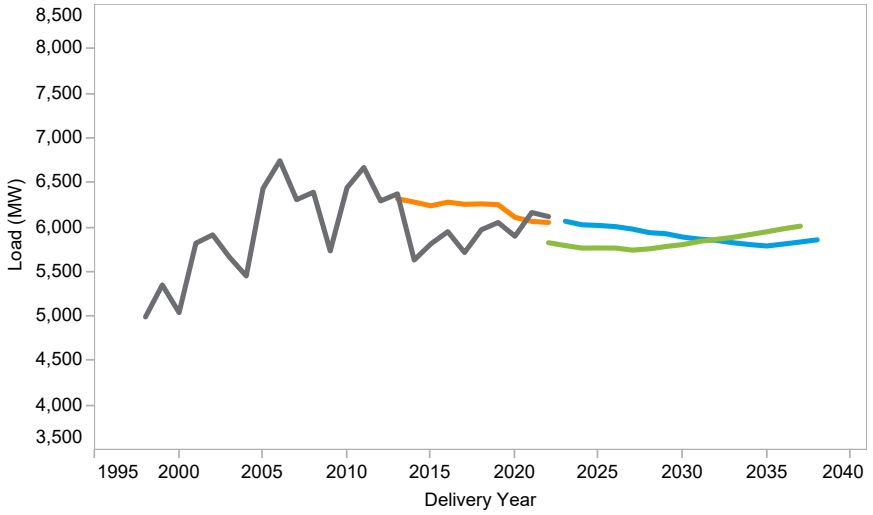
Metropolitan Statistical Areas and Weather Stations



Dover, DE
DPL - Non-Metro
Salisbury, MD-DE
Wilmington, DE-MD-NJ

Jersey Central Power and Light (JCPL)

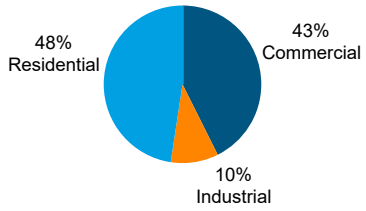
Summer Peak



Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*75.6*
Avg Summer Max Temp	*98.2*
Avg Winter Daily Temp	*35.9*
Avg Winter Min Temp	*7.6*

RCI Makeup



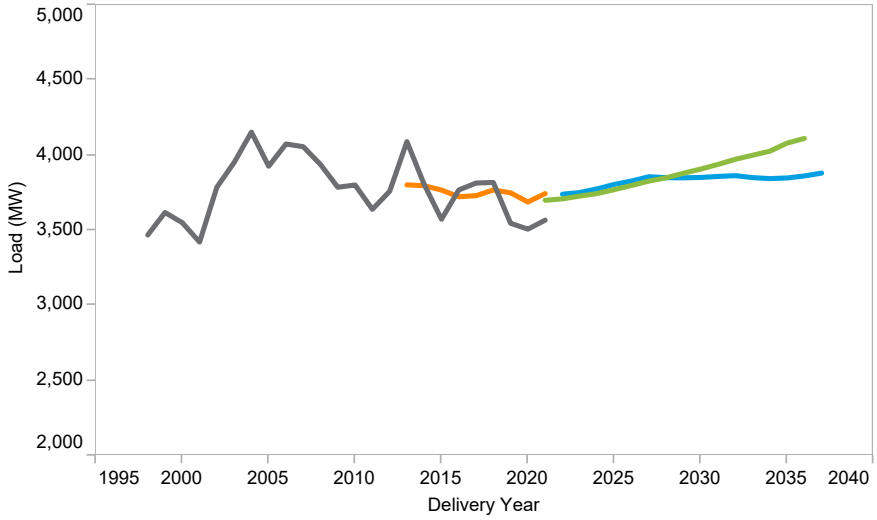
Zonal 10/15 Year Load Growth

SUMMER	-0.4%	-0.2%
WINTER	0.3%	0.2%

LDAs

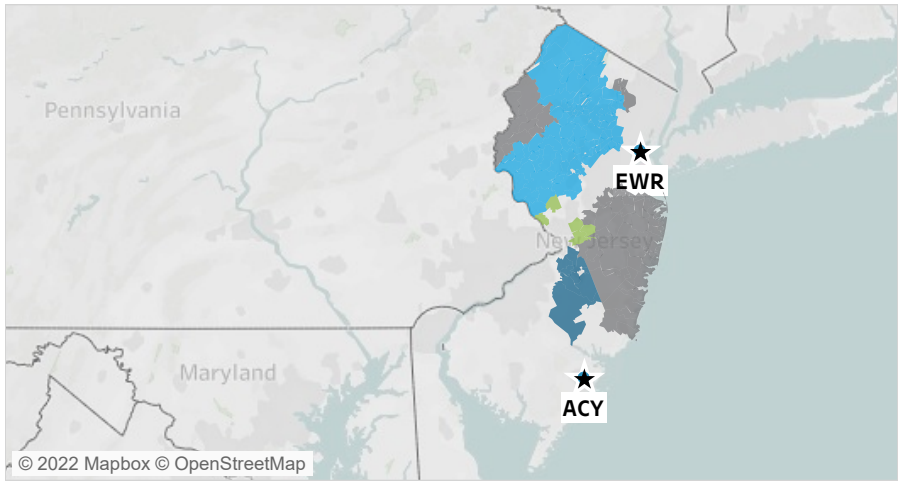
EASTERN MID-ATLANTIC FE-EAST PJM MID-ATLANTIC
PJM RTO

Winter Peak



Peak WN peak Forecast 2022 Forecast 2023

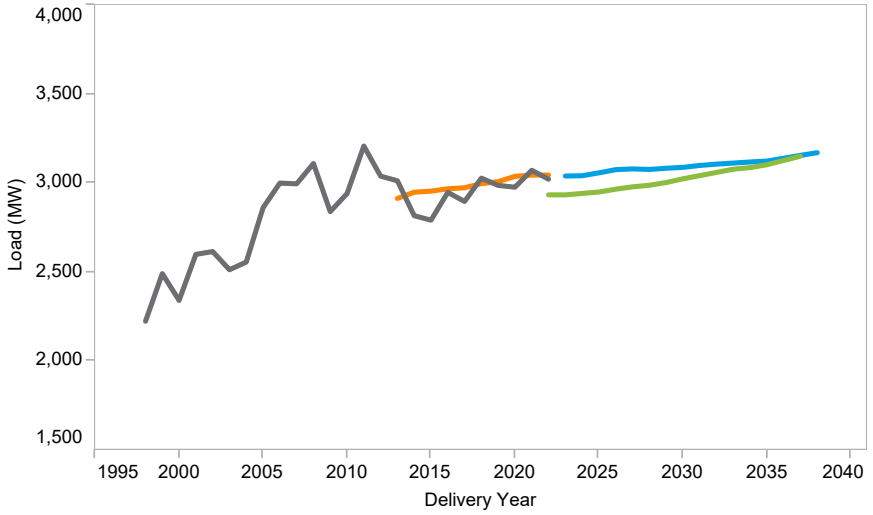
Metropolitan Statistical Areas and Weather Stations



Camden, NJ
JCPL - Non-Metro
Newark, NJ-PA
Trenton, NJ

Metropolitan Edison (METED)

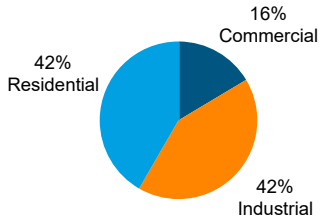
Summer Peak



Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*74.7*
Avg Summer Max Temp	*95.8*
Avg Winter Daily Temp	*34.4*
Avg Winter Min Temp	*6.6*

RCI Makeup



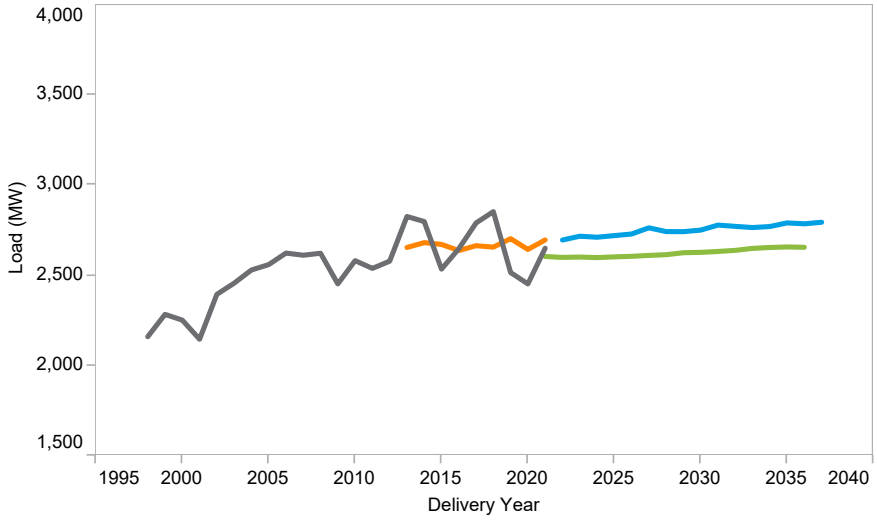
Zonal 10/15 Year Load Growth

SUMMER	0.2%	0.3%
WINTER	0.3%	0.2%

LDAs

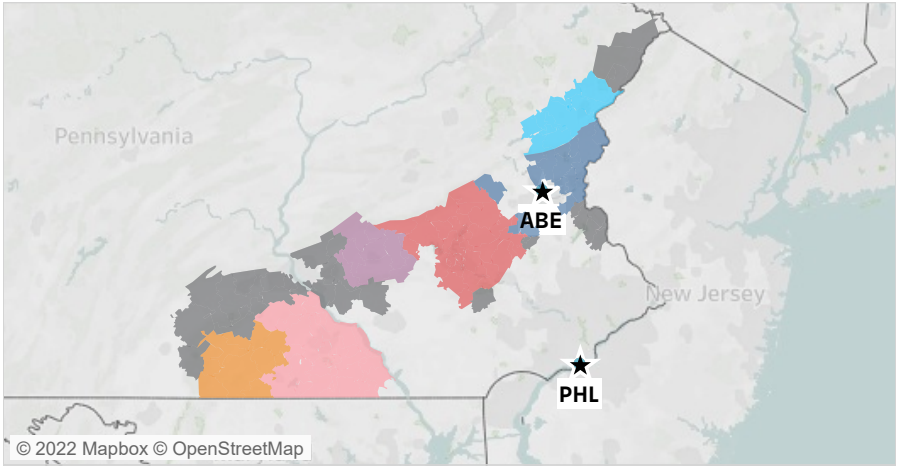
CENTRAL MID-ATLANTIC FE-EAST PJM MID-ATLANTIC
PJM RTO WESTERN MID-ATLANTIC

Winter Peak



Peak WN peak Forecast 2022 Forecast 2023

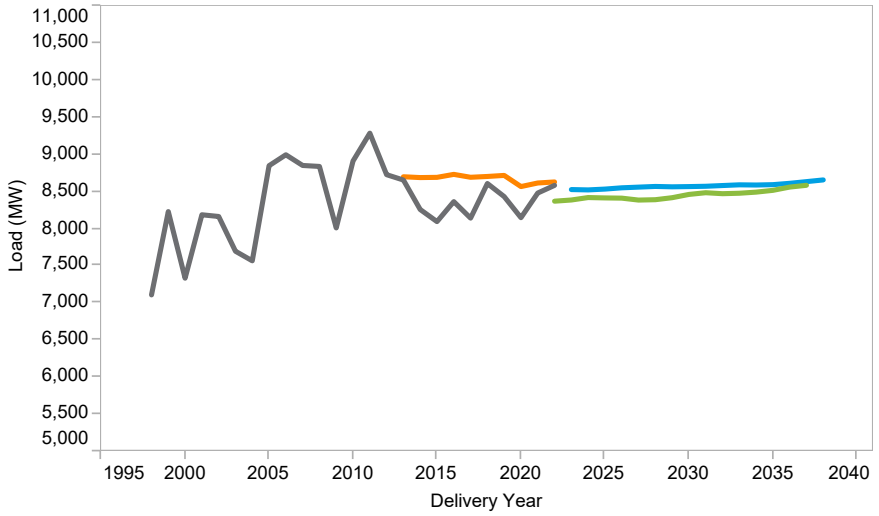
Metropolitan Statistical Areas and Weather Stations



Allentown-Bethlehem-Easton, PA-NJ
East Stroudsburg, PA
Gettysburg, PA
Lebanon, PA
METED - Non-Metro
Reading, PA
York-Hanover, PA

PECO Energy (PECO)

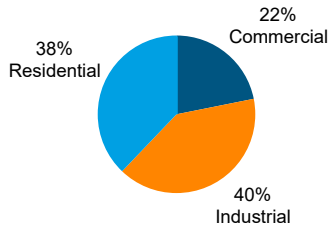
Summer Peak



Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*76.5*
Avg Summer Max Temp	*97.2*
Avg Winter Daily Temp	*36.6*
Avg Winter Min Temp	*9.3*

RCI Makeup



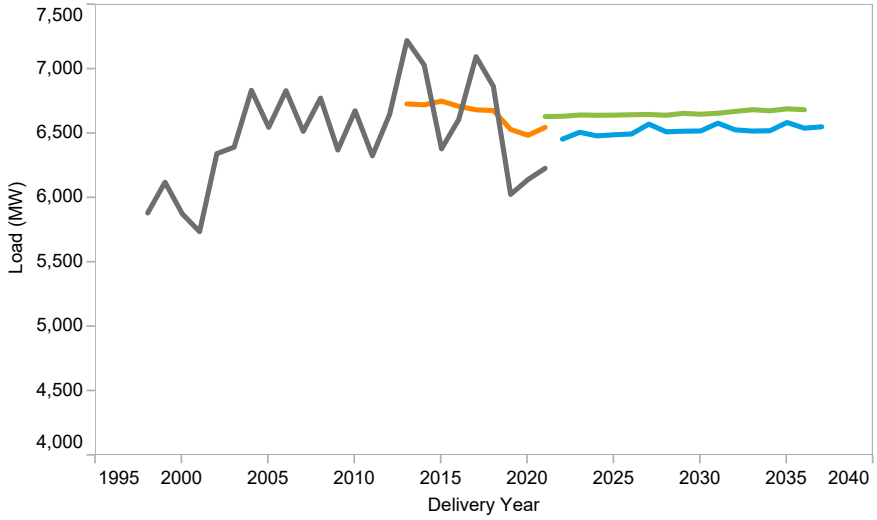
Zonal 10/15 Year Load Growth

SUMMER	0.1%	0.1%
WINTER	0.1%	0.1%

LDAs

EASTERN MID-ATLANTIC PJM MID-ATLANTIC PJM RTO

Winter Peak



Peak WN peak Forecast 2022 Forecast 2023

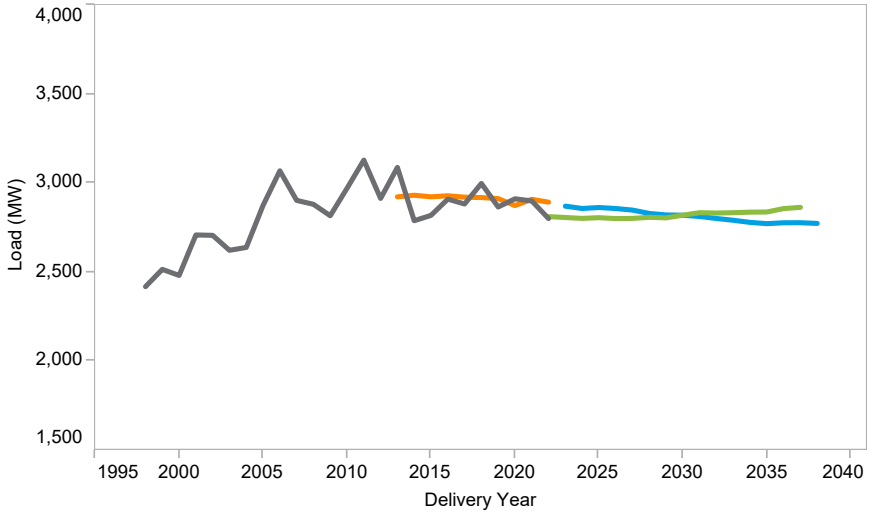
Metropolitan Statistical Areas and Weather Stations



Montgomery County-Bucks County-Chester County, PA
PECO - Non-Metro
Philadelphia, PA

Pennsylvania Electric Company (PENLC)

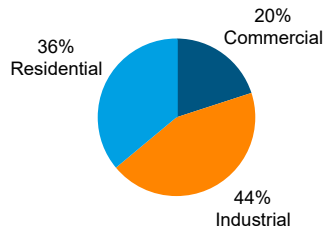
Summer Peak



Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*71.1*
Avg Summer Max Temp	*91.7*
Avg Winter Daily Temp	*30.3*
Avg Winter Min Temp	*2.0*

RCI Makeup



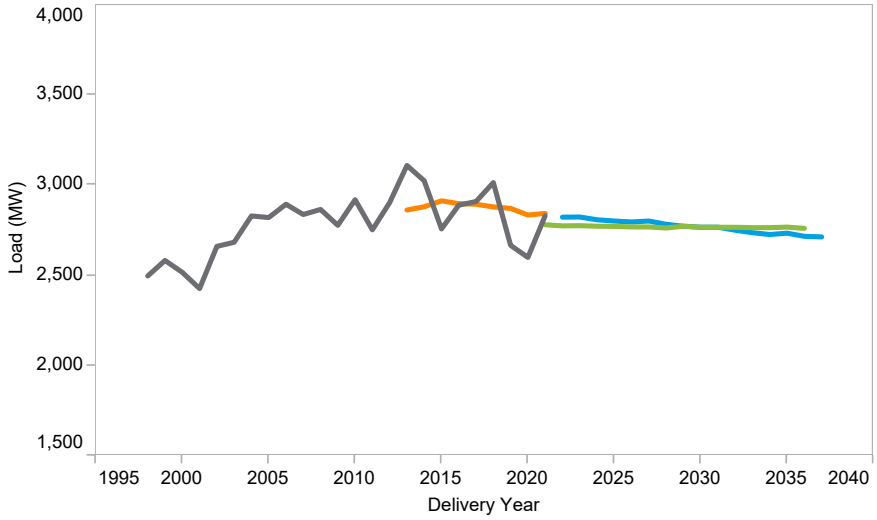
Zonal 10/15 Year Load Growth

SUMMER	-0.3%	-0.2%
WINTER	-0.3%	-0.3%

LDAs

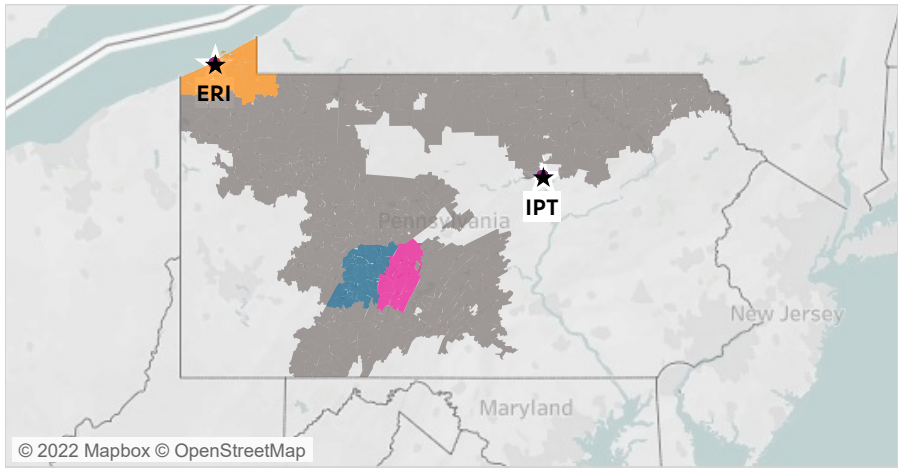
FE-EAST PJM MID-ATLANTIC PJM RTO
WESTERN MID-ATLANTIC

Winter Peak



Peak WN peak Forecast 2022 Forecast 2023

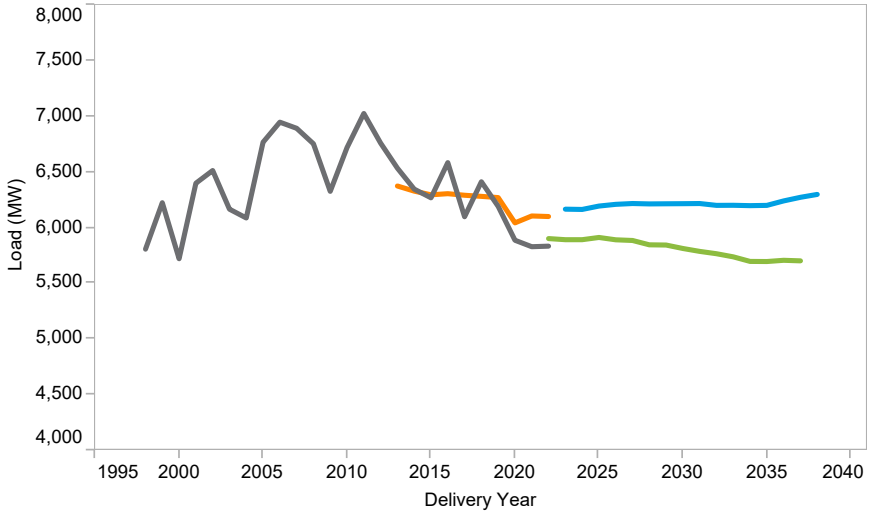
Metropolitan Statistical Areas and Weather Stations



Altoona, PA
Erie, PA
Johnstown, PA
PENLC - Non-Metro

Potomac Electric Power (PEPCO)

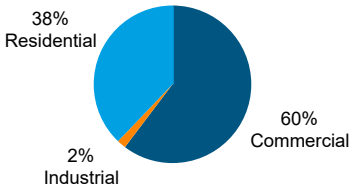
Summer Peak



Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*78.1*
Avg Summer Max Temp	*98.0*
Avg Winter Daily Temp	*39.0*
Avg Winter Min Temp	*12.8*

RCI Makeup



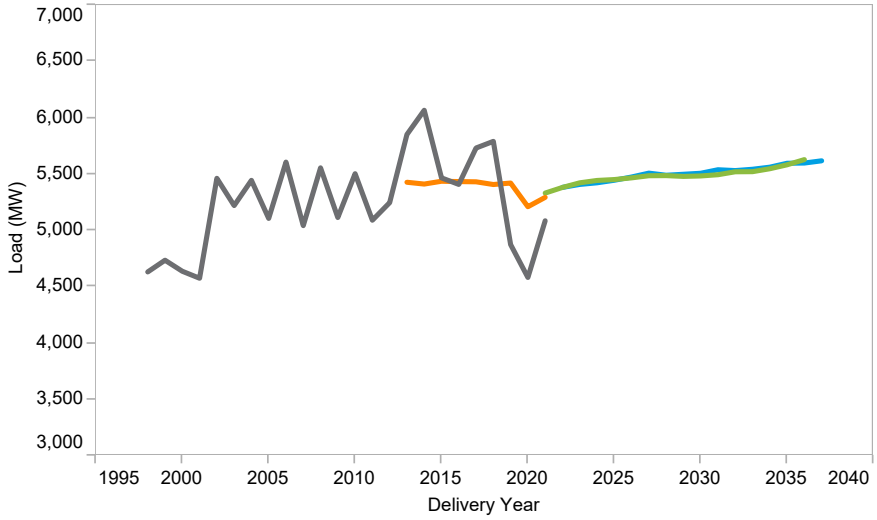
Zonal 10/15 Year Load Growth

SUMMER	0.1%	0.1%
WINTER	0.3%	0.3%

LDAs

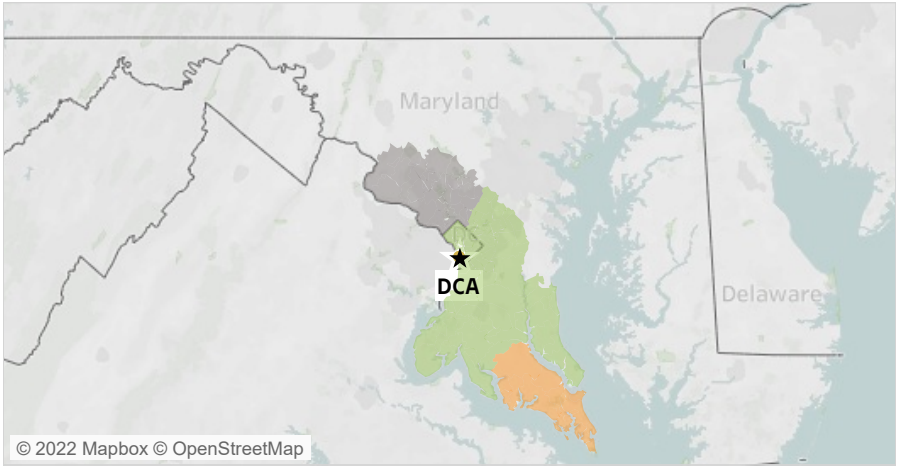
CENTRAL MID-ATLANTIC PJM MID-ATLANTIC PJM RTO
SOUTHERN MID-ATLANTIC

Winter Peak



Peak WN peak Forecast 2022 Forecast 2023

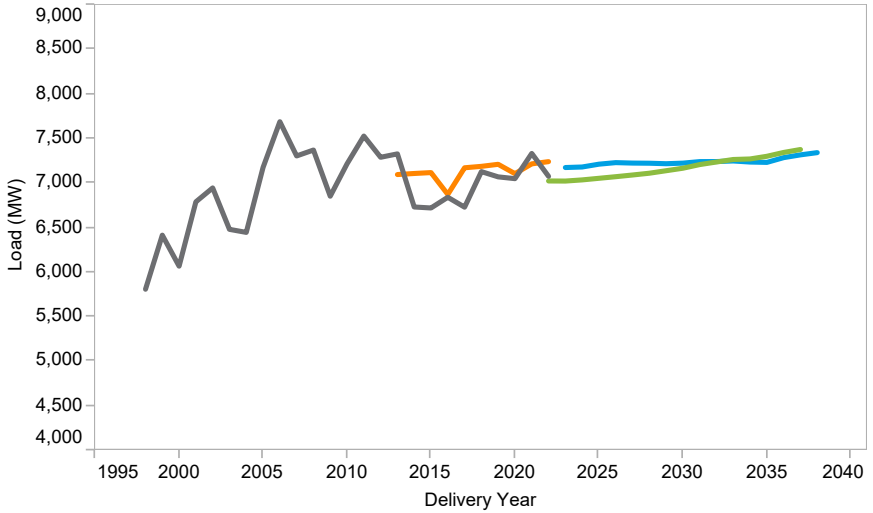
Metropolitan Statistical Areas and Weather Stations



California-Lexington Park, MD
PEPCO - Non-Metro
Washington-Arlington-Alexandria, DC-VA-MD-WV

PPL Electric Utilities (PL)

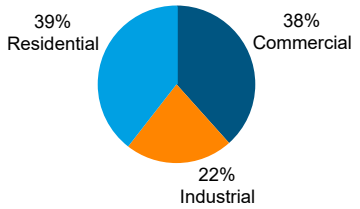
Summer Peak



Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*72.4*
Avg Summer Max Temp	*94.1*
Avg Winter Daily Temp	*31.5*
Avg Winter Min Temp	*2.8*

RCI Makeup



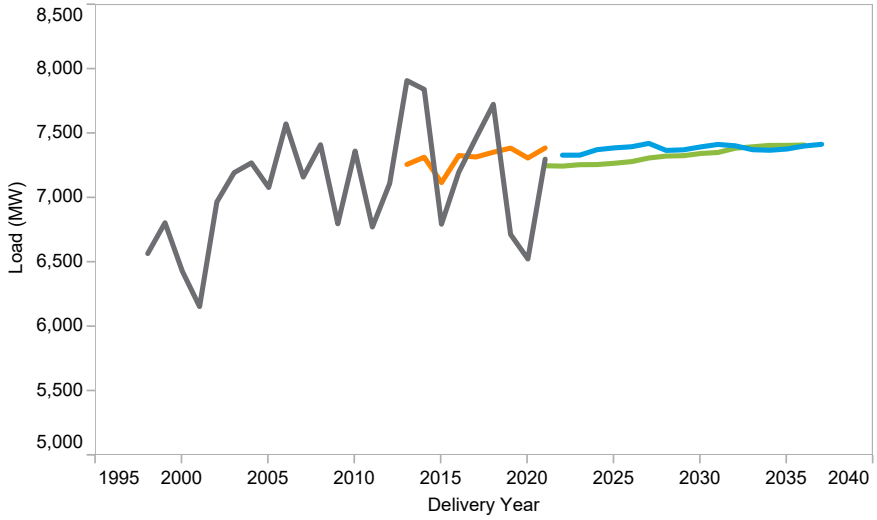
Zonal 10/15 Year Load Growth

SUMMER	0.1%	0.2%
WINTER	0.1%	0.1%

LDAs

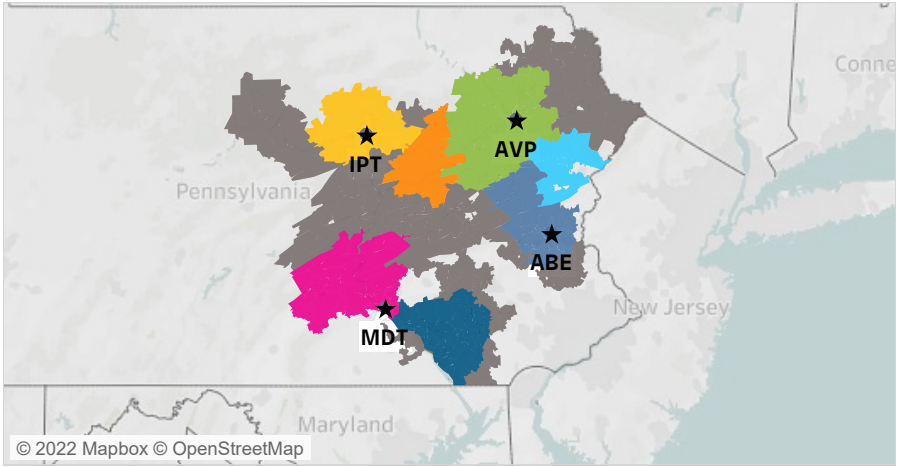
CENTRAL MID-ATLANTIC PJM MID-ATLANTIC PJM RTO
PLGRP WESTERN MID-ATLANTIC

Winter Peak



Peak WN peak Forecast 2022 Forecast 2023

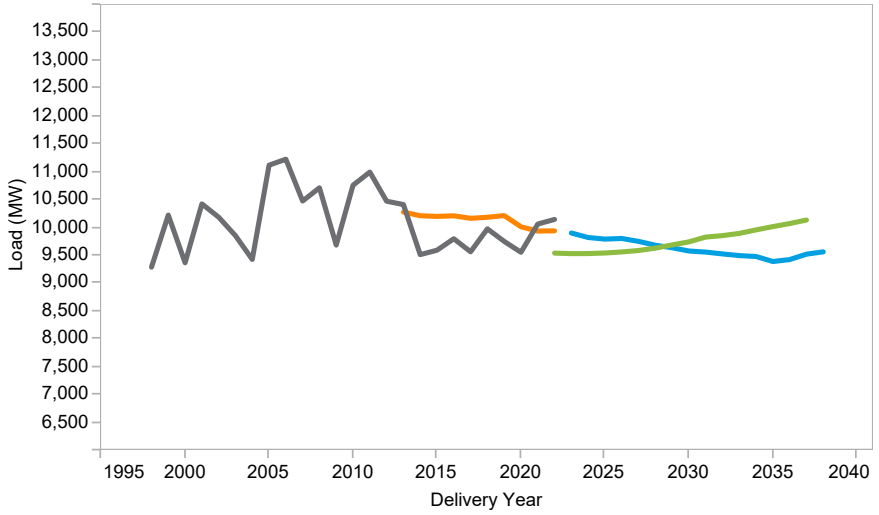
Metropolitan Statistical Areas and Weather Stations



Allentown-Bethlehem-Easton, PA-NJ
Bloomsburg-Berwick, PA
East Stroudsburg, PA
Harrisburg-Carlisle, PA
Lancaster, PA
PL - Non-Metro
Scranton--Wilkes-Barre--Hazleton, PA
Williamsport, PA

Public Service Electric & Gas (PS)

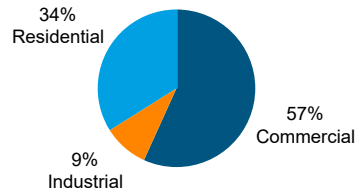
Summer Peak



Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*76.0*
Avg Summer Max Temp	*99.0*
Avg Winter Daily Temp	*35.6*
Avg Winter Min Temp	*7.5*

RCI Makeup



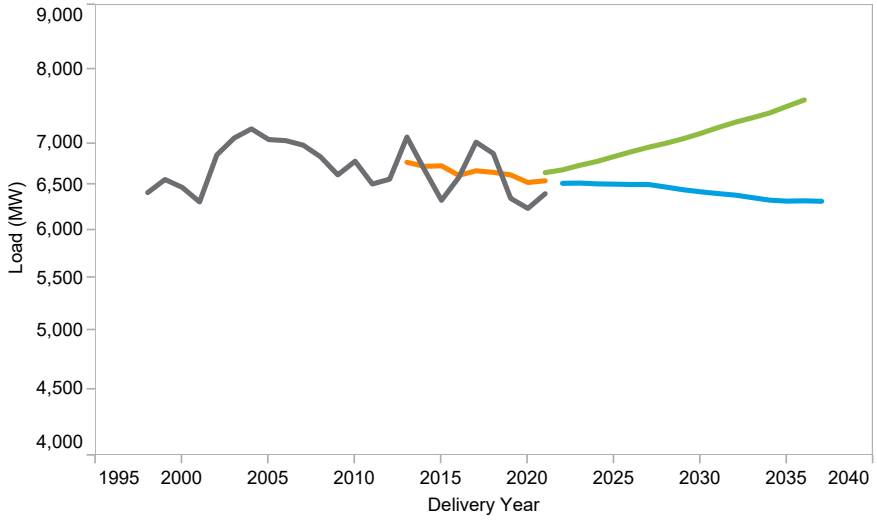
Zonal 10/15 Year Load Growth

SUMMER	-0.4%	-0.2%
WINTER	-0.2%	-0.2%

LDAs

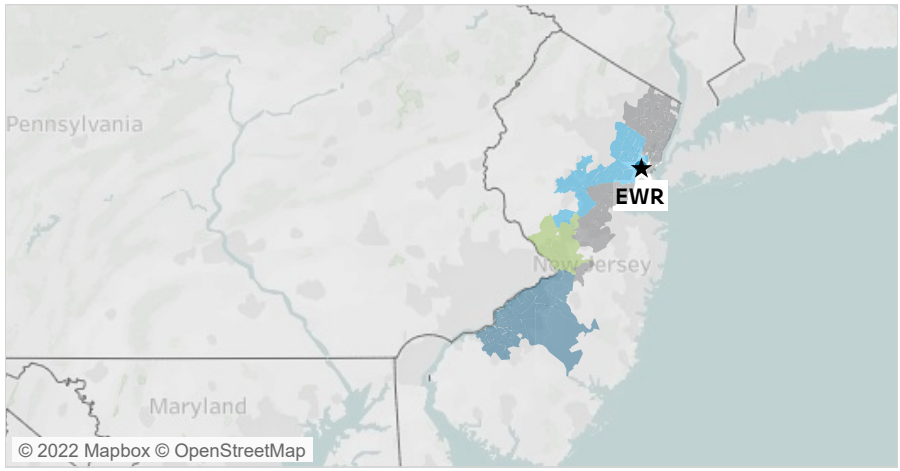
EASTERN MID-ATLANTIC PJM MID-ATLANTIC PJM RTO

Winter Peak



Peak WN peak Forecast 2022 Forecast 2023

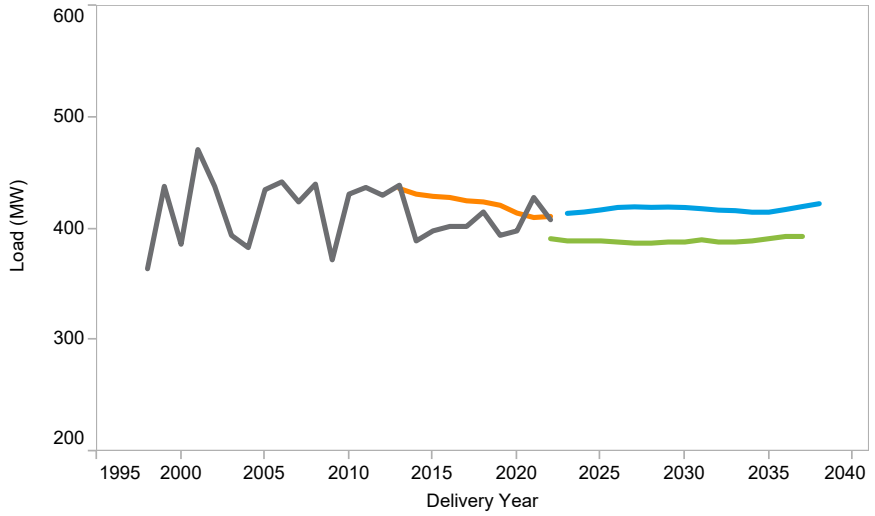
Metropolitan Statistical Areas and Weather Stations



Camden, NJ
Newark, NJ-PA
PS - Non-Metro
Trenton, NJ

Rockland Electric Company (RECO)

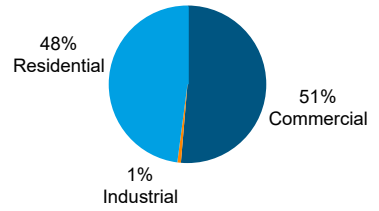
Summer Peak



Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*76.0*
Avg Summer Max Temp	*99.0*
Avg Winter Daily Temp	*35.6*
Avg Winter Min Temp	*7.5*

RCI Makeup



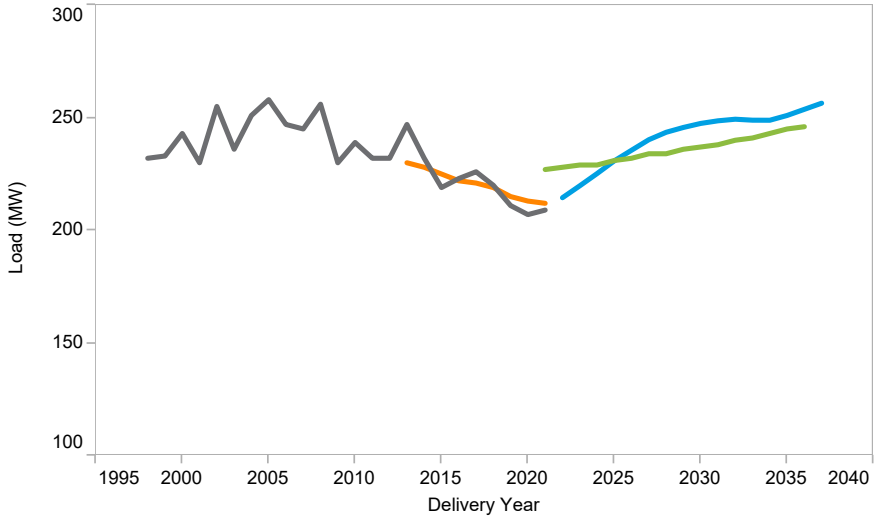
Zonal 10/15 Year Load Growth

SUMMER	0.1%	0.1%
WINTER	1.5%	1.2%

LDAs

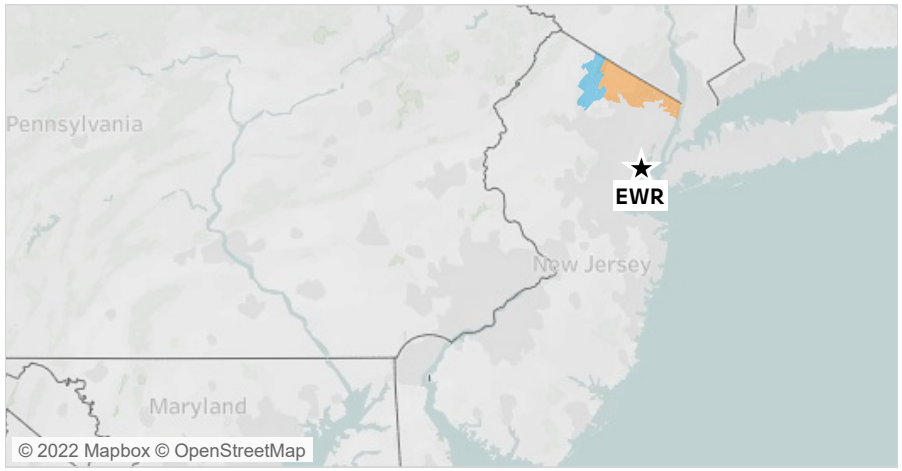
EASTERN MID-ATLANTIC PJM MID-ATLANTIC PJM RTO

Winter Peak



Peak WN peak Forecast 2022 Forecast 2023

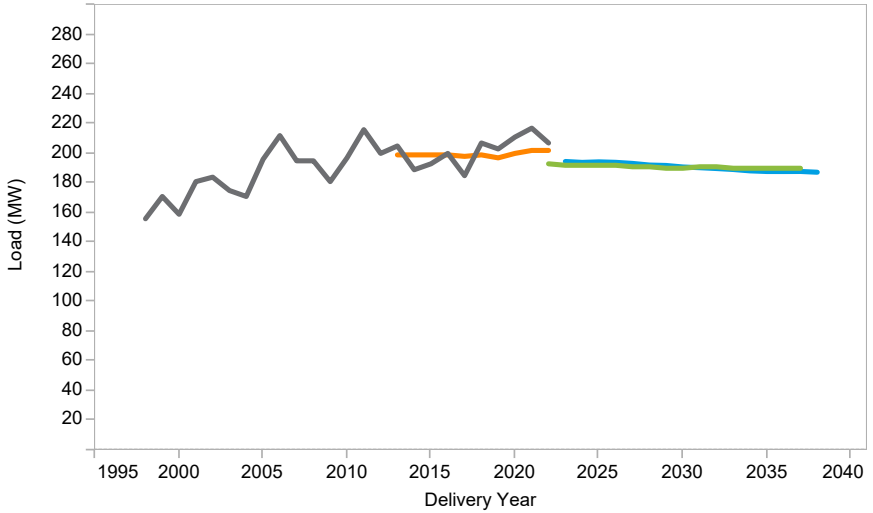
Metropolitan Statistical Areas and Weather Stations



New York-Jersey City-White Plains, NY-NJ
Newark, NJ-PA

UGI Energy Services (UGI)

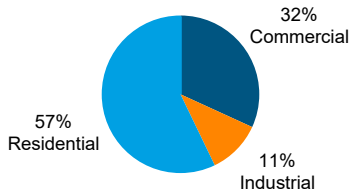
Summer Peak



Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*70.5*
Avg Summer Max Temp	*93.1*
Avg Winter Daily Temp	*30.0*
Avg Winter Min Temp	*-0.9*

RCI Makeup



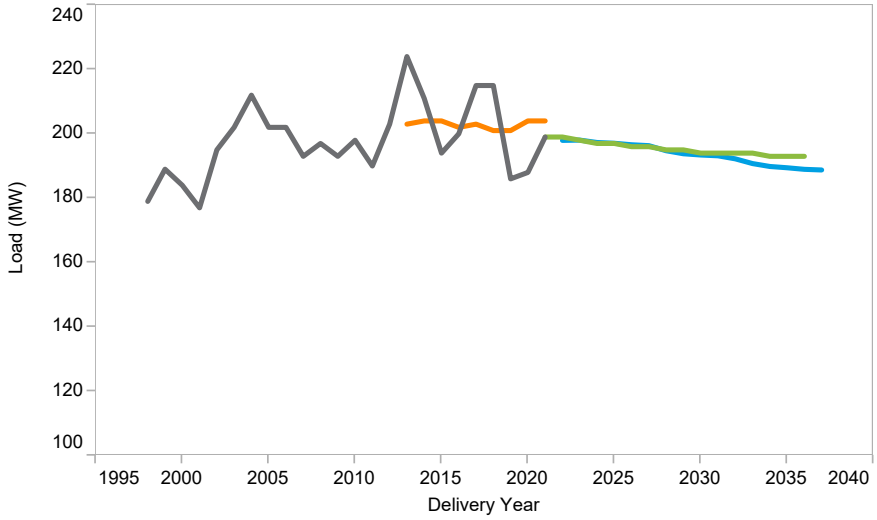
Zonal 10/15 Year Load Growth

SUMMER	-0.3%	-0.3%
WINTER	-0.3%	-0.3%

LDAs

CENTRAL MID-ATLANTIC PJM MID-ATLANTIC PJM RTO
PLGRP WESTERN MID-ATLANTIC

Winter Peak



Metropolitan Statistical Areas and Weather Stations

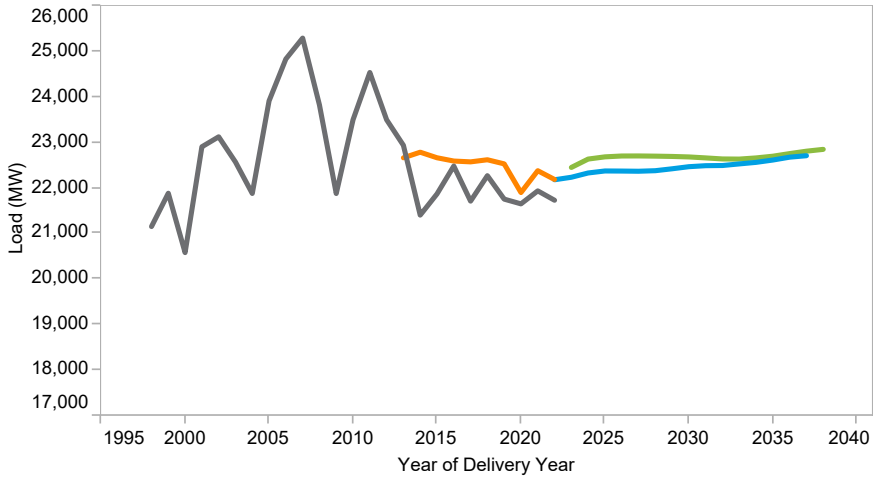


Scranton--Wilkes-Barre--Hazleton, PA

Peak WN peak Forecast 2022 Forecast 2023

American Electric Power (AEP)

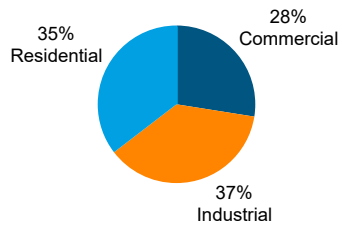
Summer Peak



Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*73.2*
Avg Summer Max Temp	*92.4*
Avg Winter Daily Temp	*33.2*
Avg Winter Min Temp	*2.7*

RCI Makeup



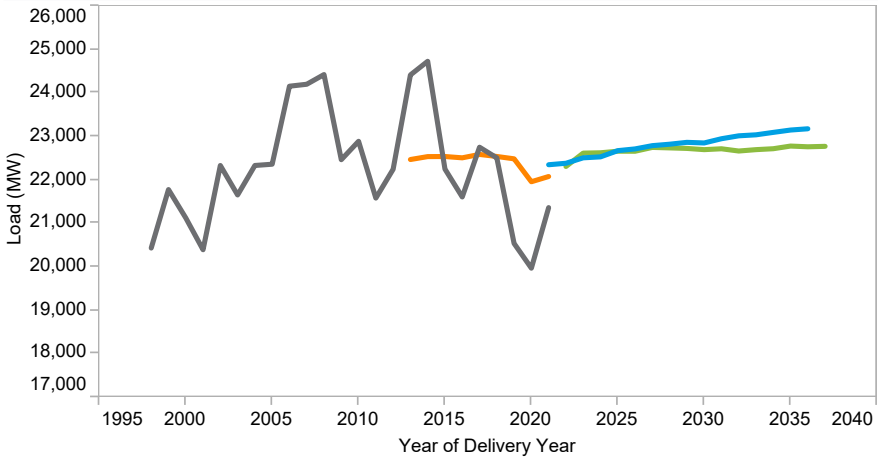
Zonal 10/15 Year Load Growth

SUMMER	0.1%	0.1%
WINTER	0.2%	0.1%

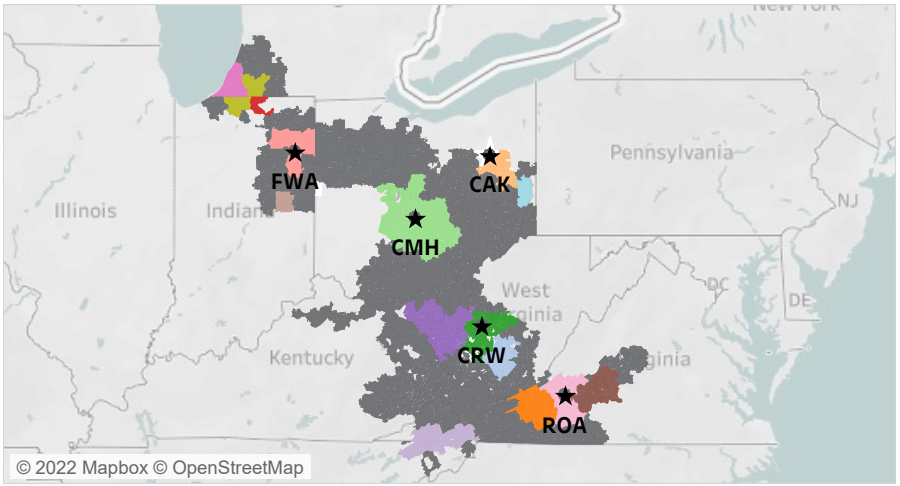
LDAs

PJM RTO PJM WESTERN

Winter Peak



Metropolitan Statistical Areas and Weather Stations

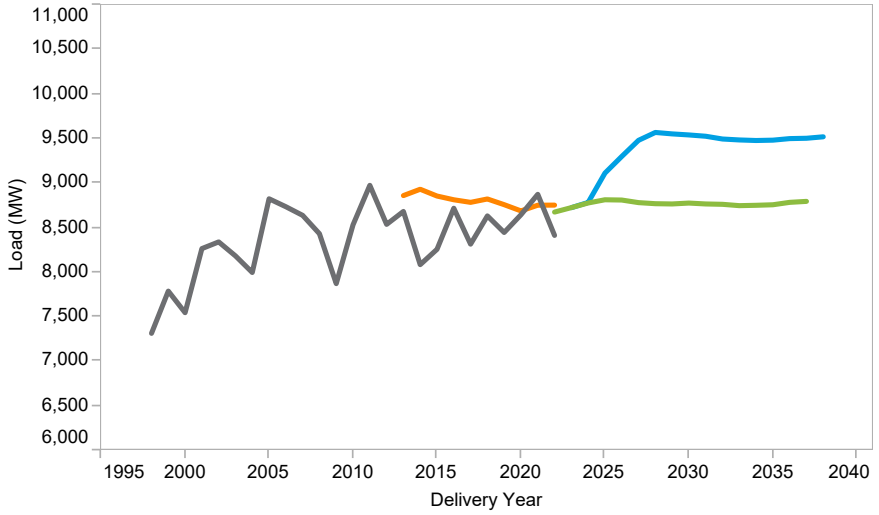


Peak
WN peak
Forecast 2022
Forecast 2023

AEP - Non-Metro
Beckley, WV
Blacksburg-Christiansburg-Radford, VA
Canton-Massillon, OH
Charleston, WV
Columbus, OH
Elkhart-Goshen, IN
Fort Wayne, IN
Huntington-Ashland, WV-KY-OH
Kingsport-Bristol-Bristol, TN-VA
Lynchburg, VA
Muncie, IN
Niles-Benton Harbor, MI
Roanoke, VA
South Bend-Mishawaka, IN-MI
Weirton-Steubenville, WV-OH

Allegheny Power Systems (APS)

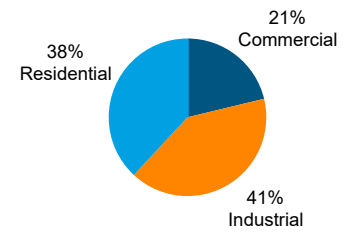
Summer Peak



Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*72.8*
Avg Summer Max Temp	*92.7*
Avg Winter Daily Temp	*32.9*
Avg Winter Min Temp	*2.3*

RCI Makeup



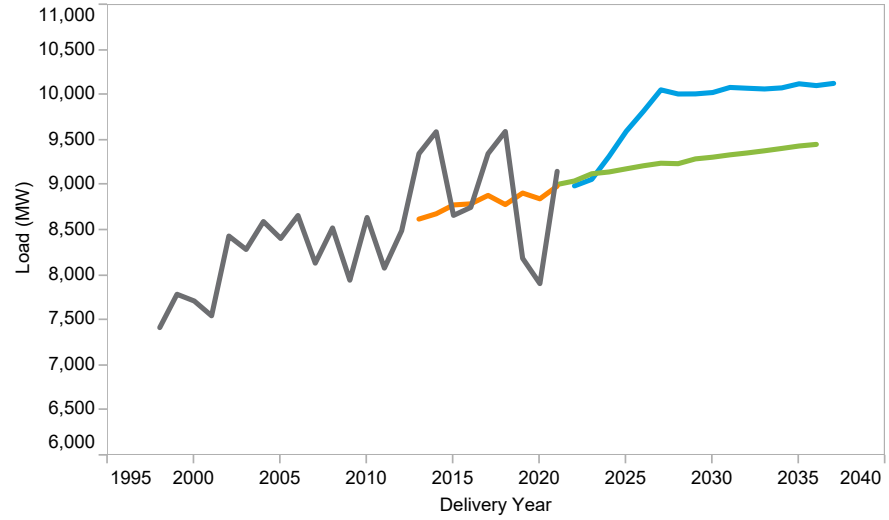
Zonal 10/15 Year Load Growth

SUMMER	0.8%	0.6%
WINTER	1.1%	0.8%

LDAs

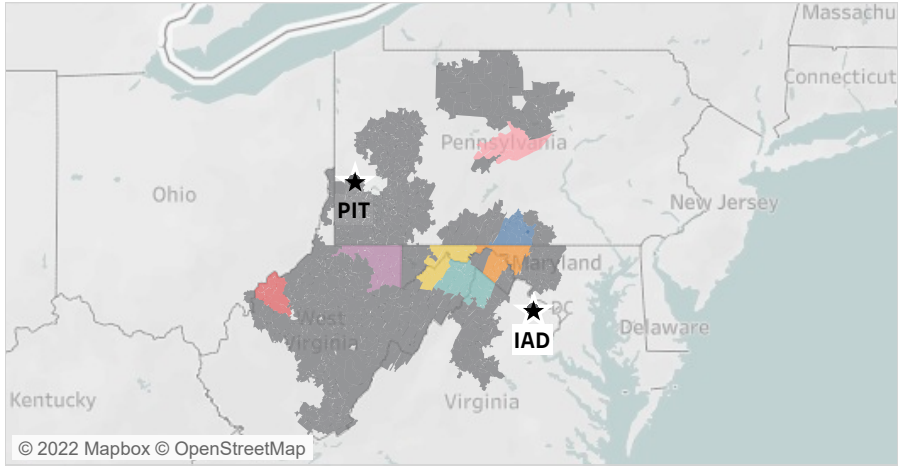
PJM RTO PJM WESTERN

Winter Peak



Peak WN peak Forecast 2022 Forecast 2023

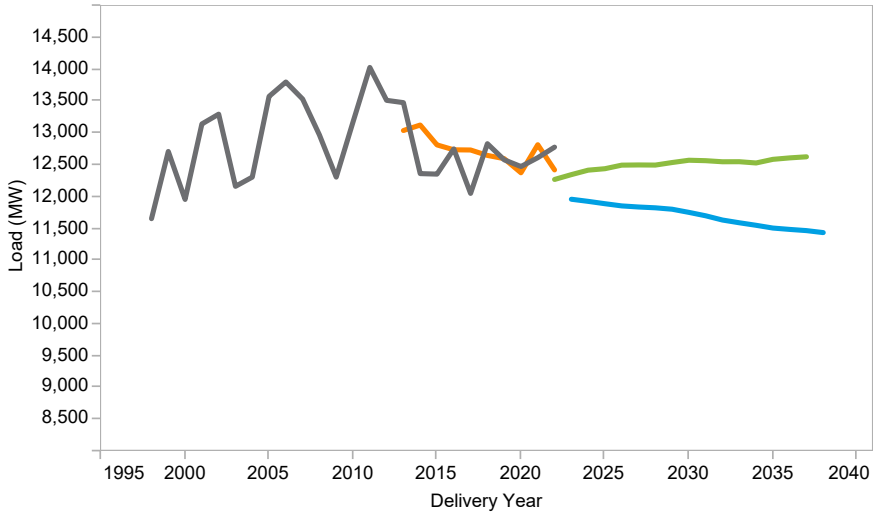
Metropolitan Statistical Areas and Weather Stations



APS - Non-metro
Chambersburg-Waynesboro, PA
Cumberland, MD-WV
Hagerstown-Martinsburg, MD-WV
Morgantown, WV
Parkersburg-Vienna, WV
State College, PA
Winchester, VA-WV

American Transmission Systems, Inc. (ATSI)

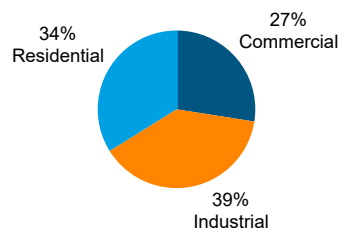
Summer Peak



Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*71.6*
Avg Summer Max Temp	*91.9*
Avg Winter Daily Temp	*29.9*
Avg Winter Min Temp	*-1.3*

RCI Makeup



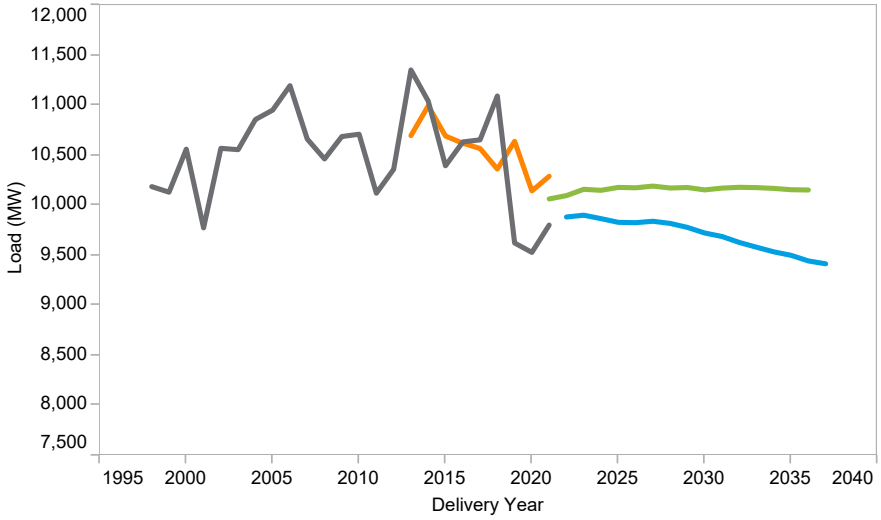
Zonal 10/15 Year Load Growth

SUMMER	-0.3%	-0.3%
WINTER	-0.3%	-0.3%

LDAs

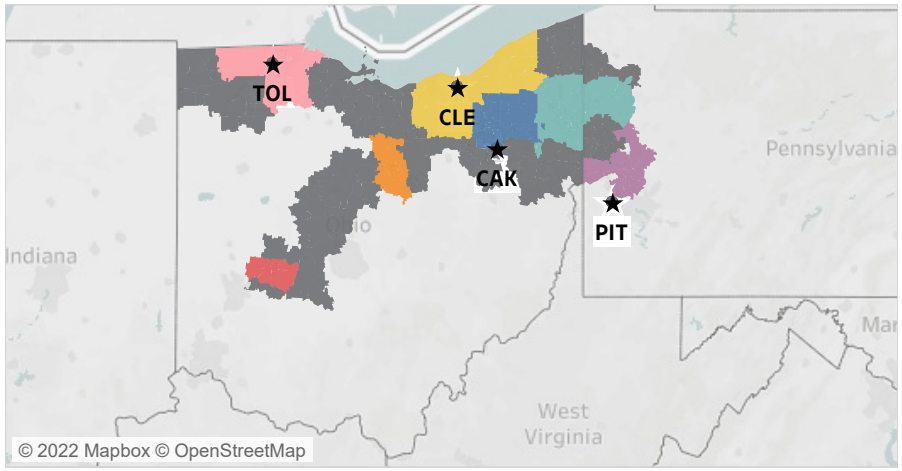
PJM RTO PJM WESTERN

Winter Peak



Peak WN peak Forecast 2022 Forecast 2023

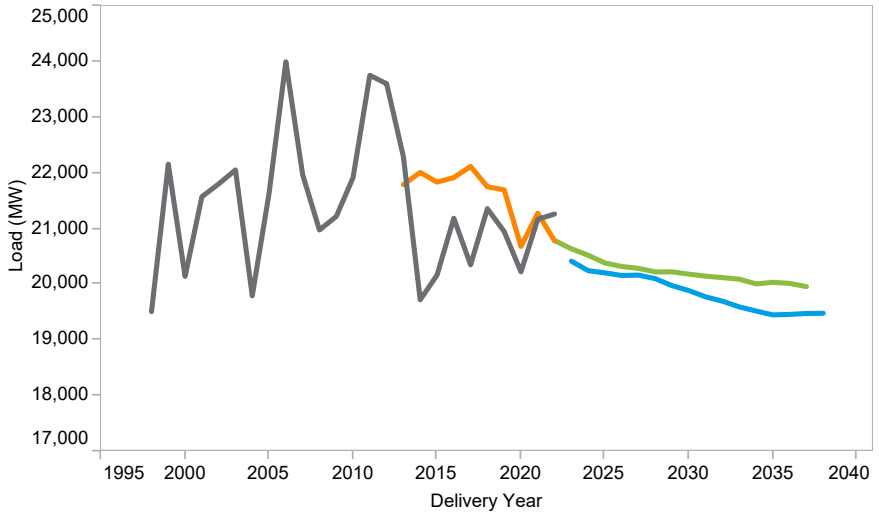
Metropolitan Statistical Areas and Weather Stations



Akron, OH
ATSI - Non-Metro
Cleveland-Elyria, OH
Mansfield, OH
Pittsburgh, PA
Springfield, OH
Toledo, OH
Youngstown-Warren-Boardman, OH-PA

Commonweath Edison (COMED)

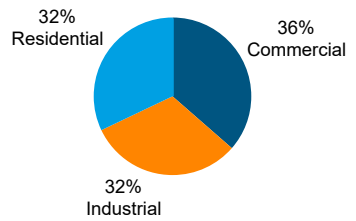
Summer Peak



Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*72.9*
Avg Summer Max Temp	*95.2*
Avg Winter Daily Temp	*27.6*
Avg Winter Min Temp	*-7.3*

RCI Makeup



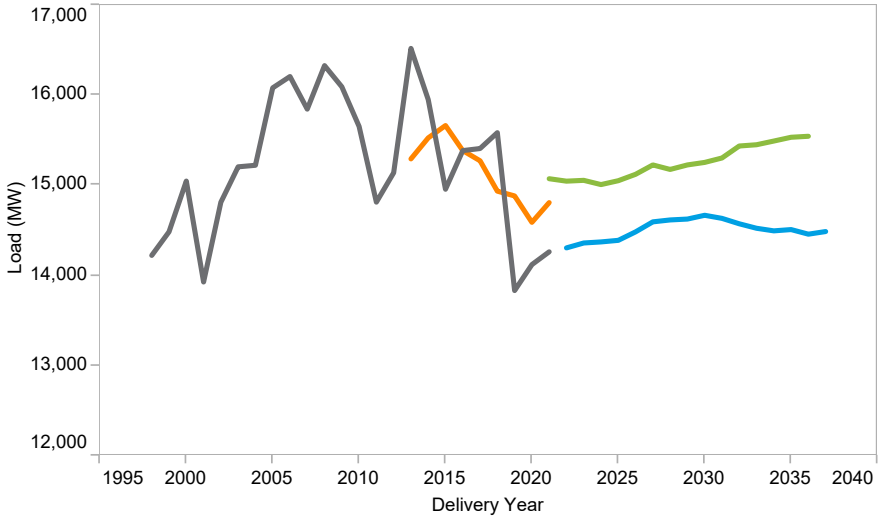
Zonal 10/15 Year Load Growth

SUMMER	-0.4%	-0.3%
WINTER	0.2%	0.1%

LDAs

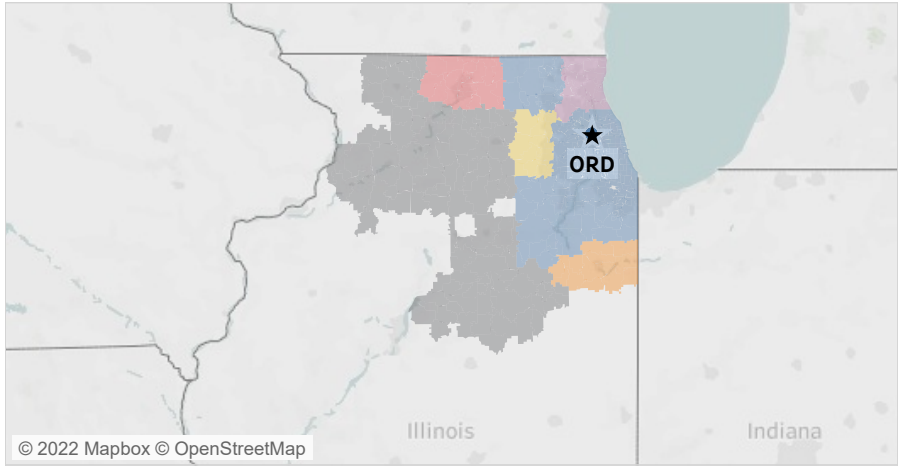
PJM RTO PJM WESTERN

Winter Peak



Peak WN peak Forecast 2022 Forecast 2023

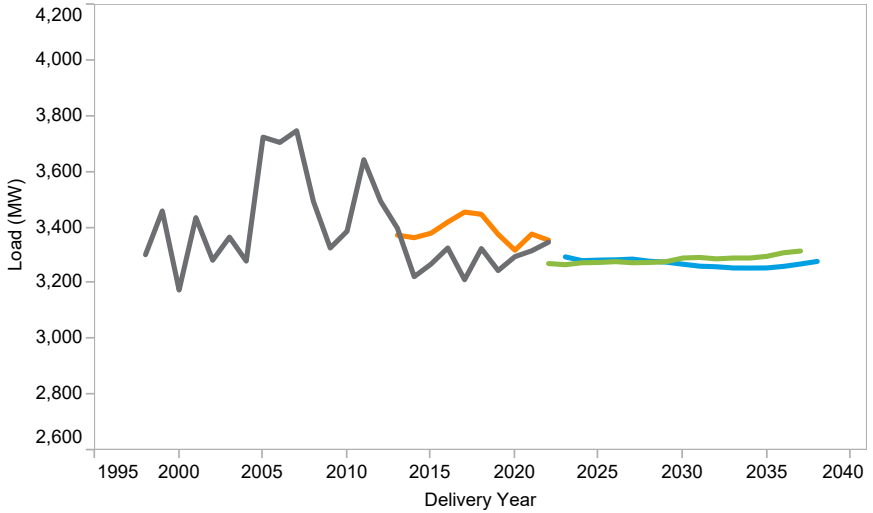
Metropolitan Statistical Areas and Weather Stations



Chicago-Naperville-Arlington Heights, IL
Chicago-Naperville-Elgin, IL-IN-WI
COMED - Non-Metro
Kankakee, IL
Lake County-Kenosha County, IL-WI
Rockford, IL

Dayton Power and Light (DAYTON)

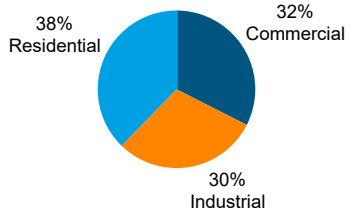
Summer Peak



Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*73.1*
Avg Summer Max Temp	*93.1*
Avg Winter Daily Temp	*31.0*
Avg Winter Min Temp	*-3.3*

RCI Makeup



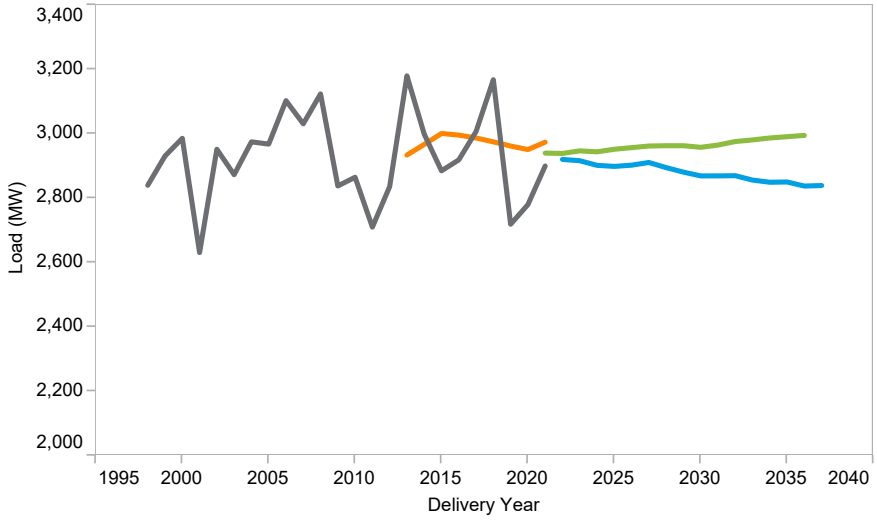
Zonal 10/15 Year Load Growth

SUMMER	-0.1%	0.0%
WINTER	-0.2%	-0.2%

LDAs

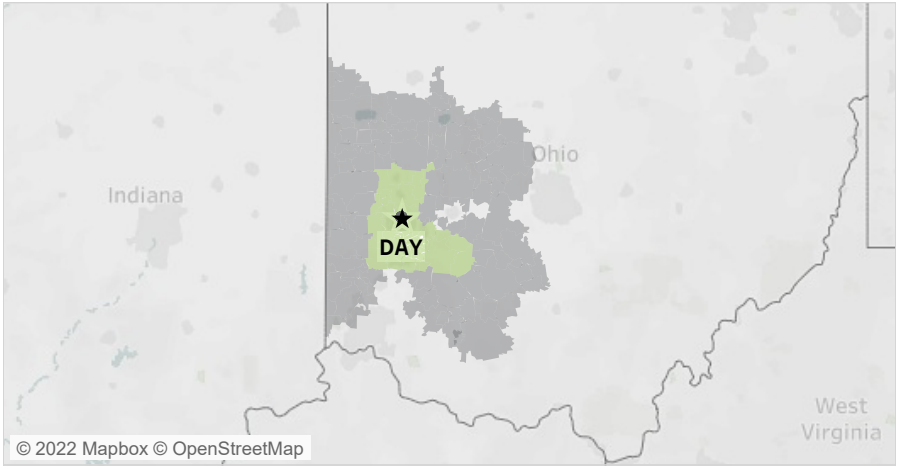
PJM RTO PJM WESTERN

Winter Peak



Peak WN peak Forecast 2022 Forecast 2023

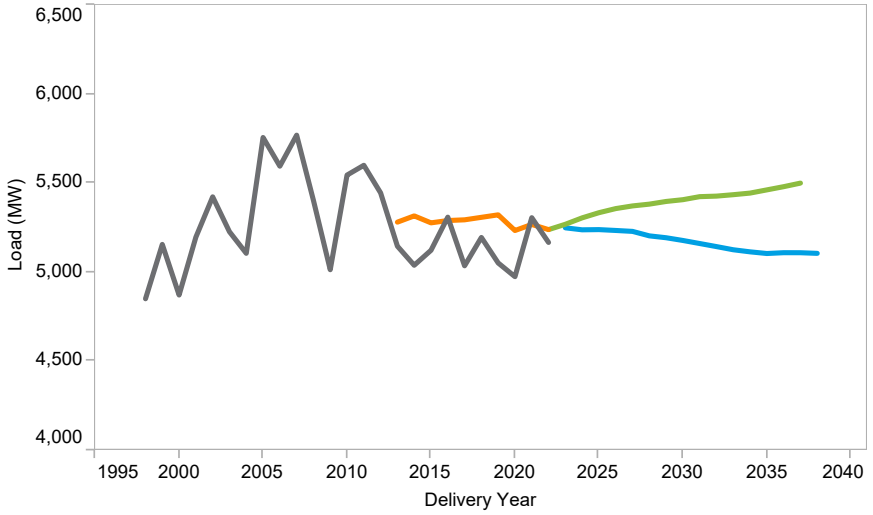
Metropolitan Statistical Areas and Weather Stations



DAY - Non-Metro
Dayton, OH

Duke Energy Ohio and Kentucky (DEOK)

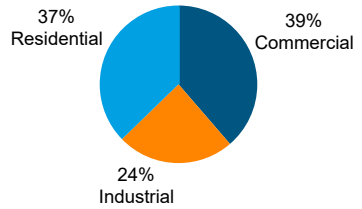
Summer Peak



Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*74.4*
Avg Summer Max Temp	*94.2*
Avg Winter Daily Temp	*33.9*
Avg Winter Min Temp	*-1.4*

RCI Makeup



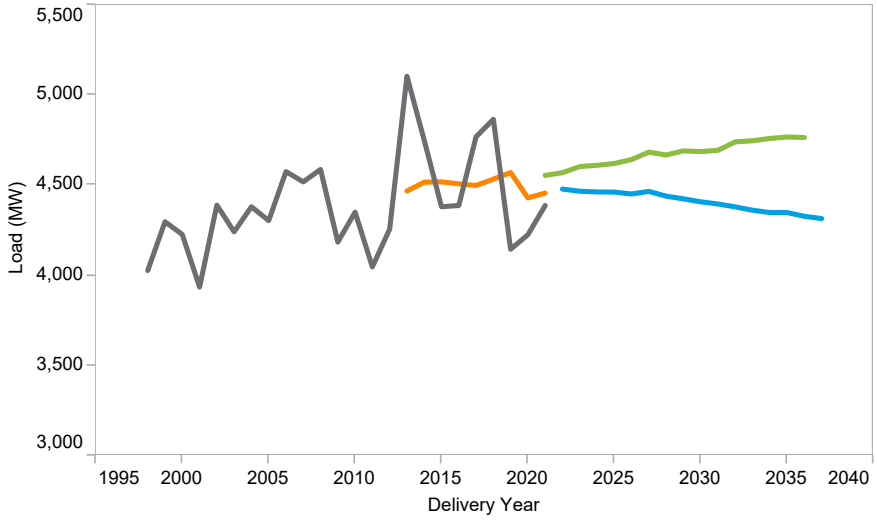
Zonal 10/15 Year Load Growth

SUMMER	-0.2%	-0.2%
WINTER	-0.2%	-0.2%

LDAs

PJM RTO PJM WESTERN

Winter Peak



Peak WN peak Forecast 2022 Forecast 2023

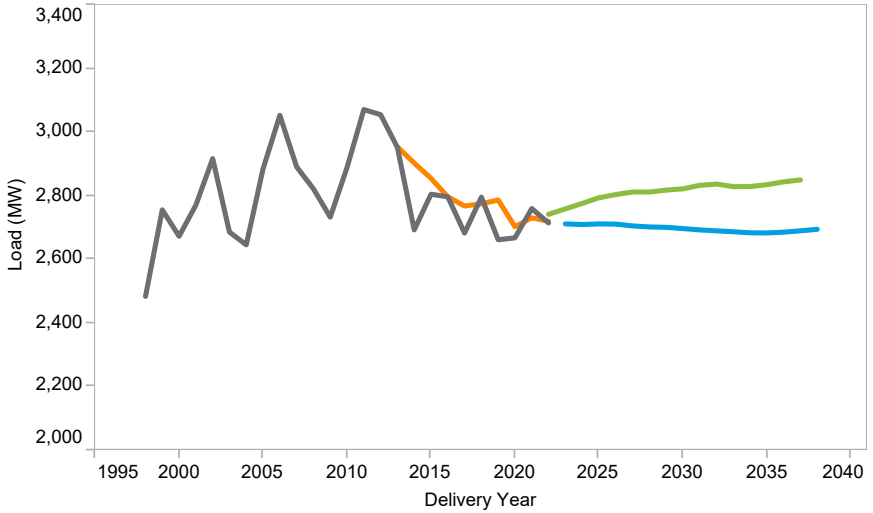
Metropolitan Statistical Areas and Weather Stations



Cincinnati, OH-KY-IN
DEOK - Non-Metro

Duquesne Light Company (DLCO)

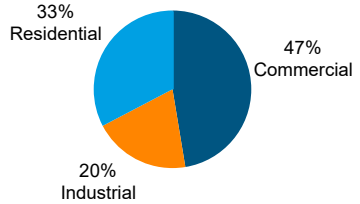
Summer Peak



Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*71.7*
Avg Summer Max Temp	*91.8*
Avg Winter Daily Temp	*31.5*
Avg Winter Min Temp	*-0.9*

RCI Makeup



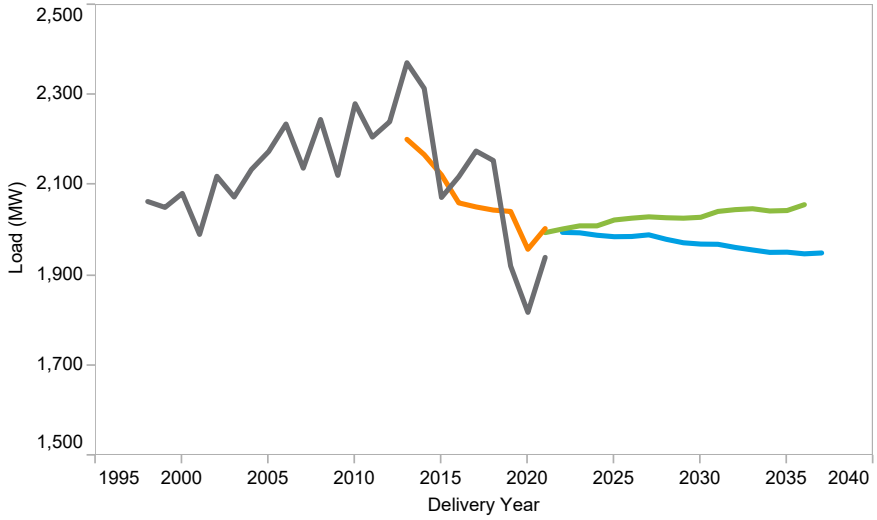
Zonal 10/15 Year Load Growth

SUMMER	-0.1%	0.0%
WINTER	-0.2%	-0.2%

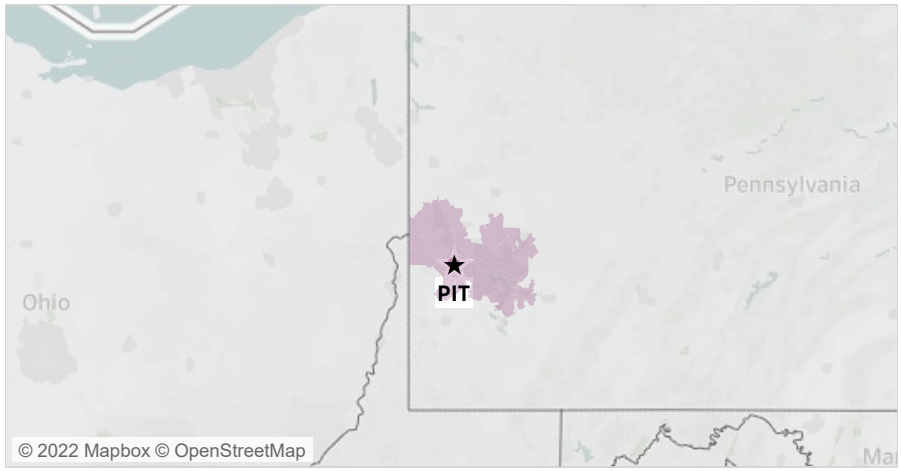
LDAs

PJM RTO PJM WESTERN

Winter Peak



Metropolitan Statistical Areas and Weather Stations

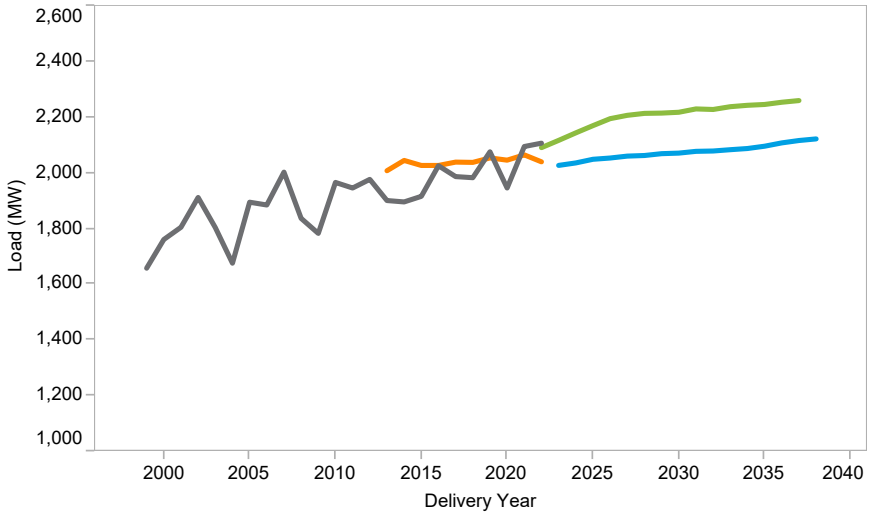


Pittsburgh, PA

Peak WN peak Forecast 2022 Forecast 2023

East Kentucky Power Cooperative (EKPC)

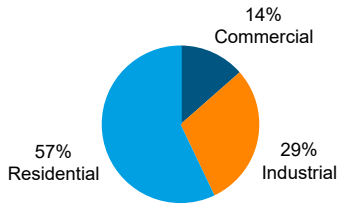
Summer Peak



Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*75.5*
Avg Summer Max Temp	*94.3*
Avg Winter Daily Temp	*35.9*
Avg Winter Min Temp	*2.1*

RCI Makeup



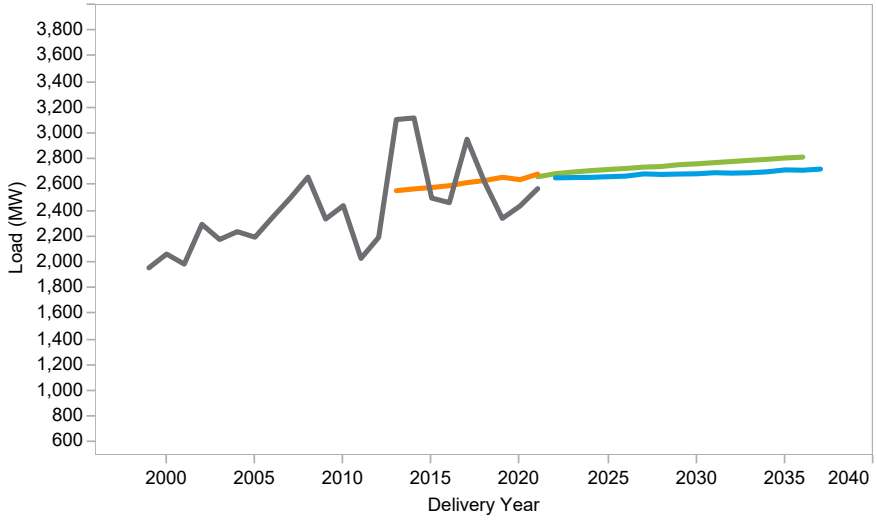
Zonal 10/15 Year Load Growth

SUMMER	0.3%	0.3%
WINTER	0.1%	0.2%

LDAs

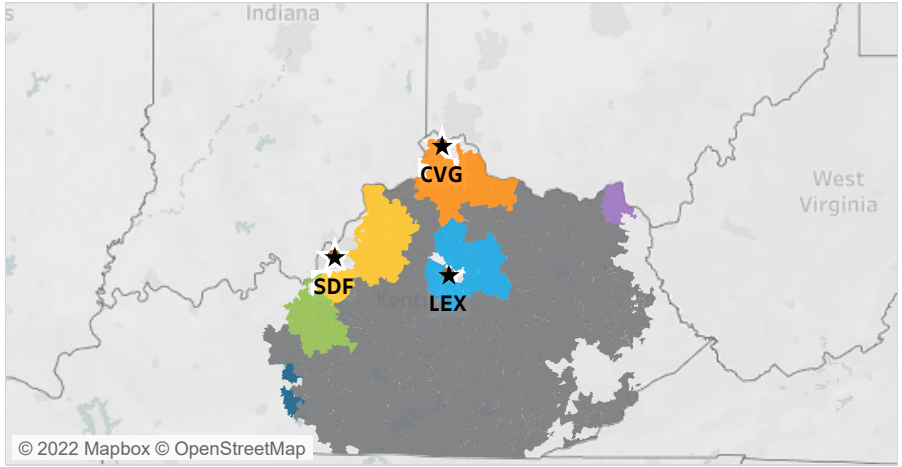
PJM RTO PJM WESTERN

Winter Peak



Peak WN peak Forecast 2022 Forecast 2023

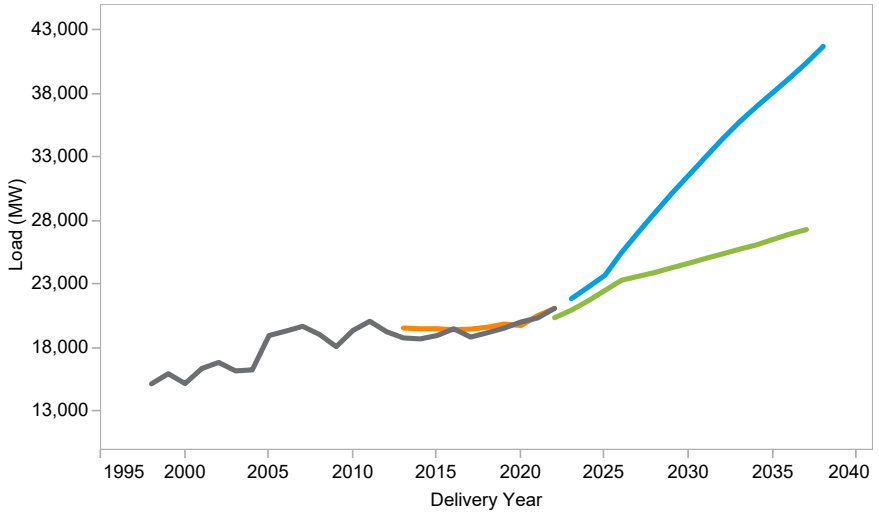
Metropolitan Statistical Areas and Weather Stations



- Bowling Green, KY
- Cincinnati, OH-KY-IN
- EKPC - Non-Metro
- Elizabethtown-Fort Knox, KY
- Huntington-Ashland, WV-KY-OH
- Lexington-Fayette, KY
- Louisville/Jefferson County, KY-IN

Dominion (DOM)

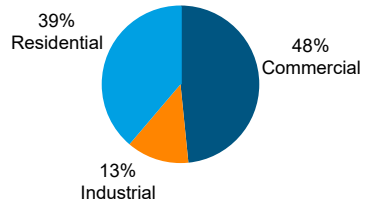
Summer Peak



Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*76.9*
Avg Summer Max Temp	*97.0*
Avg Winter Daily Temp	*40.3*
Avg Winter Min Temp	*12.3*

RCI Makeup



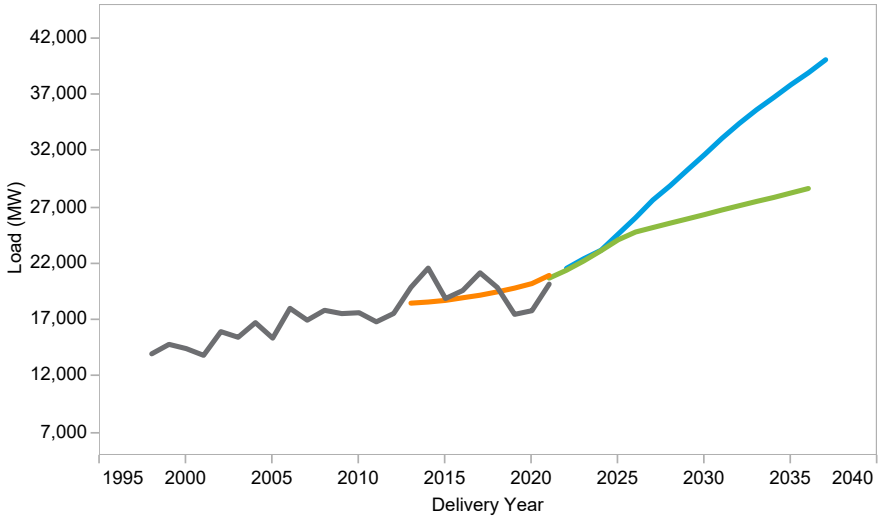
Zonal 10/15 Year Load Growth

SUMMER	5.0%	4.4%
WINTER	4.8%	4.2%

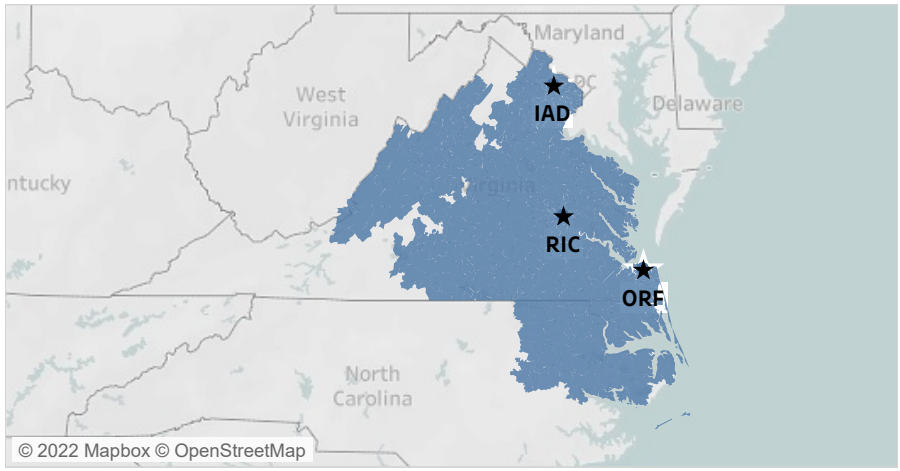
LDAs

PJM RTO

Winter Peak



Metropolitan Statistical Areas and Weather Stations



Virginia Commonwealth Economics

Peak WN peak Forecast 2022 Forecast 2023

Table A-1

PJM MID-ATLANTIC REGION
SUMMER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST
TO THE JANUARY 2022 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	2023		2028		2033	
	MW	**%**	**MW**	**%**	**MW**	**%**
AE	59	2.4%	(22)	-0.9%	(134)	-5.3%
BGE	83	1.3%	(84)	-1.3%	(260)	-4.1%
DPL	(21)	-0.5%	(152)	-3.9%	(162)	-4.2%
JCPL	273	4.7%	183	3.2%	(62)	-1.1%
METED	106	3.6%	89	3.0%	34	1.1%
PECO	141	1.7%	178	2.1%	113	1.3%
PENLC	64	2.3%	22	0.8%	(42)	-1.5%
PEPCO	274	4.7%	367	6.3%	463	8.1%
PL	152	2.2%	112	1.6%	(17)	-0.2%
PS	370	3.9%	53	0.6%	(398)	-4.0%
RECO	25	6.4%	32	8.3%	28	7.2%
UGI	3	1.6%	1	0.5%	(1)	-0.5%
PJM MID-ATLANTIC	664	1.2%	(205)	-0.4%	(1,266)	-2.3%
FE-EAST	400	3.5%	312	2.8%	(53)	-0.5%
PLGRP	168	2.3%	135	1.9%	5	0.1%

Table A-1

PJM WESTERN REGION, PJM SOUTHERN REGION AND PJM RTO
SUMMER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST
TO THE JANUARY 2022 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	2023		2028		2033	
	MW	**%**	**MW**	**%**	**MW**	**%**
AEP	215	1.0%	320	1.4%	106	0.5%
APS	(1)	-0.0%	799	9.1%	737	8.4%
ATSI	(387)	-3.1%	(671)	-5.4%	(959)	-7.6%
COMED	(221)	-1.1%	(121)	-0.6%	(498)	-2.5%
DAYTON	28	0.9%	5	0.2%	(36)	-1.1%
DEOK	(20)	-0.4%	(178)	-3.3%	(309)	-5.7%
DLCO	(47)	-1.7%	(110)	-3.9%	(142)	-5.0%
EKPC	(90)	-4.3%	(151)	-6.8%	(154)	-6.9%
OVEC	5	5.6%	5	5.6%	5	5.6%
PJM WESTERN	(397)	-0.5%	12	0.0%	(1,299)	-1.7%
DOM	907	4.3%	4,715	19.7%	9,982	38.7%
PJM RTO	(292)	-0.2%	3,014	2.0%	6,204	4.0%

Table A-2

PJM MID-ATLANTIC REGION
WINTER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST
TO THE JANUARY 2022 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	22/23		27/28		32/33	
	MW	**%**	**MW**	**%**	**MW**	**%**
AE	(29)	-1.8%	(79)	-4.7%	(160)	-9.3%
BGE	(47)	-0.8%	(234)	-3.9%	(498)	-8.1%
DPL	(5)	-0.1%	(75)	-2.0%	(188)	-4.8%
JCPL	30	0.8%	29	0.8%	(109)	-2.7%
METED	96	3.7%	153	5.9%	133	5.0%
PECO	(177)	-2.7%	(75)	-1.1%	(144)	-2.2%
PENLC	48	1.7%	33	1.2%	(16)	-0.6%
PEPCO	0	0.0%	23	0.4%	11	0.2%
PL	85	1.2%	113	1.5%	19	0.3%
PS	(160)	-2.4%	(454)	-6.5%	(896)	-12.3%
RECO	(14)	-6.1%	6	2.6%	9	3.8%
UGI	(1)	-0.5%	0	0.0%	(2)	-1.0%
PJM MID-ATLANTIC	(479)	-1.0%	(749)	-1.6%	(2,022)	-4.2%
FE-EAST	181	2.0%	191	2.1%	7	0.1%
PLGRP	85	1.1%	117	1.6%	21	0.3%

Table A-2

PJM WESTERN REGION, PJM SOUTHERN REGION AND PJM RTO
WINTER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST
TO THE JANUARY 2022 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	22/23		27/28		32/33	
	MW	**%**	**MW**	**%**	**MW**	**%**
AEP	(74)	-0.3%	(41)	-0.2%	(350)	-1.5%
APS	(55)	-0.6%	814	8.8%	718	7.7%
ATSI	(214)	-2.1%	(351)	-3.4%	(551)	-5.4%
COMED	(741)	-4.9%	(632)	-4.2%	(863)	-5.6%
DAYTON	(19)	-0.6%	(51)	-1.7%	(106)	-3.6%
DEOK	(91)	-2.0%	(218)	-4.7%	(361)	-7.6%
DLCO	(7)	-0.3%	(40)	-2.0%	(84)	-4.1%
EKPC	(32)	-1.2%	(52)	-1.9%	(91)	-3.3%
OVEC	(5)	-4.3%	(5)	-4.3%	(5)	-4.3%
PJM WESTERN	(1,512)	-2.2%	(946)	-1.4%	(1,910)	-2.8%
DOM	165	0.8%	2,440	9.7%	7,299	26.8%
PJM RTO	(2,169)	-1.6%	453	0.3%	2,678	1.9%

Table B-1

SUMMER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION 2023 - 2033

	METERED 2022	UNRESTRICTED 2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Annual Growth Rate (10 yr)
AE	2,615	2,615	2,549	2,526	2,516	2,504	2,492	2,481	2,467	2,452	2,438	2,426	2,418	(0.5%)
				-0.9%	-0.4%	-0.5%	-0.5%	-0.4%	-0.6%	-0.6%	-0.6%	-0.5%	-0.3%	
BGE	6,521	6,521	6,474	6,428	6,406	6,378	6,350	6,307	6,243	6,203	6,160	6,105	6,060	(0.7%)
				-0.7%	-0.3%	-0.4%	-0.4%	-0.7%	-1.0%	-0.6%	-0.7%	-0.9%	-0.7%	
DPL	4,126	4,126	3,861	3,841	3,823	3,807	3,791	3,765	3,747	3,726	3,701	3,680	3,666	(0.5%)
				-0.5%	-0.5%	-0.4%	-0.4%	-0.7%	-0.5%	-0.6%	-0.7%	-0.6%	-0.4%	
JCPL	6,124	6,124	6,072	6,032	6,025	6,011	5,984	5,945	5,932	5,894	5,871	5,857	5,830	(0.4%)
				-0.7%	-0.1%	-0.2%	-0.4%	-0.7%	-0.2%	-0.6%	-0.4%	-0.2%	-0.5%	
METED	3,022	3,022	3,040	3,041	3,058	3,076	3,080	3,077	3,083	3,088	3,099	3,106	3,112	0.2%
				0.0%	0.6%	0.6%	0.1%	-0.1%	0.2%	0.2%	0.4%	0.2%	0.2%	
PECO	8,583	8,583	8,527	8,522	8,533	8,550	8,559	8,568	8,563	8,567	8,571	8,581	8,590	0.1%
				-0.1%	0.1%	0.2%	0.1%	0.1%	-0.1%	0.0%	0.0%	0.1%	0.1%	
PENLC	2,801	2,801	2,871	2,858	2,863	2,857	2,848	2,830	2,821	2,820	2,813	2,801	2,792	(0.3%)
				-0.5%	0.2%	-0.2%	-0.3%	-0.6%	-0.3%	-0.0%	-0.2%	-0.4%	-0.3%	
PEPCO	5,834	5,834	6,166	6,164	6,194	6,209	6,217	6,213	6,214	6,215	6,217	6,200	6,201	0.1%
				-0.0%	0.5%	0.2%	0.1%	-0.1%	0.0%	0.0%	0.0%	-0.3%	0.0%	
PL	7,065	7,076	7,175	7,181	7,212	7,230	7,225	7,223	7,218	7,224	7,241	7,242	7,248	0.1%
				0.1%	0.4%	0.2%	-0.1%	-0.0%	-0.1%	0.1%	0.2%	0.0%	0.1%	
PS	10,148	10,148	9,904	9,824	9,795	9,806	9,754	9,685	9,639	9,581	9,561	9,529	9,499	(0.4%)
				-0.8%	-0.3%	0.1%	-0.5%	-0.7%	-0.5%	-0.6%	-0.2%	-0.3%	-0.3%	
RECO	408	408	414	415	417	419	420	419	419	419	418	417	416	0.0%
				0.2%	0.5%	0.5%	0.2%	-0.2%	0.0%	0.0%	-0.2%	-0.2%	-0.2%	
UGI	207	207	195	194	194	194	193	192	192	191	190	190	189	(0.3%)
				-0.5%	0.0%	0.0%	-0.5%	-0.5%	0.0%	-0.5%	-0.5%	0.0%	-0.5%	
DIVERSITY - MID-ATLANTIC(-)			1,512	1,576	1,617	1,606	1,611	1,736	1,800	1,966	2,002	1,627	1,685	
PJM MID-ATLANTIC	56,443	56,449	55,736	55,450	55,419	55,435	55,302	54,969	54,738	54,414	54,278	54,507	54,336	(0.3%)
				-0.5%	-0.1%	0.0%	-0.2%	-0.6%	-0.4%	-0.6%	-0.2%	0.4%	-0.3%	
FE-EAST	11,712	11,712	11,696	11,673	11,686	11,680	11,647	11,617	11,590	11,547	11,523	11,509	11,482	(0.2%)
				-0.2%	0.1%	-0.1%	-0.3%	-0.3%	-0.2%	-0.4%	-0.2%	-0.1%	-0.2%	
PLGRP	7,262	7,277	7,370	7,375	7,406	7,423	7,417	7,415	7,410	7,410	7,431	7,432	7,437	0.1%
				0.1%	0.4%	0.2%	-0.1%	-0.0%	-0.1%	0.0%	0.3%	0.0%	0.1%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2023).
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 2034 - 2038

	2034	2035	2036	2037	2038	Annual Growth Rate (15 yr)
AE	2,407	2,399	2,399	2,399	2,402	(0.4%)
	-0.5%	-0.3%	0.0%	0.0%	0.1%	
BGE	6,005	5,975	5,966	5,972	5,972	(0.5%)
	-0.9%	-0.5%	-0.2%	0.1%	0.0%	
DPL	3,653	3,649	3,651	3,655	3,660	(0.4%)
	-0.4%	-0.1%	0.1%	0.1%	0.1%	
JCPL	5,810	5,794	5,816	5,839	5,864	(0.2%)
	-0.3%	-0.3%	0.4%	0.4%	0.4%	
METED	3,118	3,124	3,140	3,156	3,171	0.3%
	0.2%	0.2%	0.5%	0.5%	0.5%	
PECO	8,588	8,593	8,611	8,633	8,656	0.1%
	-0.0%	0.1%	0.2%	0.3%	0.3%	
PENLC	2,780	2,772	2,777	2,778	2,774	(0.2%)
	-0.4%	-0.3%	0.2%	0.0%	-0.1%	
PEPCO	6,198	6,200	6,240	6,273	6,298	0.1%
	-0.0%	0.0%	0.6%	0.5%	0.4%	
PL	7,236	7,233	7,286	7,317	7,342	0.2%
	-0.2%	-0.0%	0.7%	0.4%	0.3%	
PS	9,482	9,392	9,427	9,524	9,566	(0.2%)
	-0.2%	-0.9%	0.4%	1.0%	0.4%	
RECO	415	415	417	420	422	0.1%
	-0.2%	0.0%	0.5%	0.7%	0.5%	
UGI	188	188	188	188	187	(0.3%)
	-0.5%	0.0%	0.0%	0.0%	-0.5%	
DIVERSITY - MID-ATLANTIC(-)	1,865	1,784	1,851	1,600	1,654	
PJM MID-ATLANTIC	54,015	53,950	54,067	54,554	54,660	(0.1%)
	-0.6%	-0.1%	0.2%	0.9%	0.2%	
FE-EAST	11,448	11,445	11,471	11,497	11,523	(0.1%)
	-0.3%	-0.0%	0.2%	0.2%	0.2%	
PLGRP	7,424	7,421	7,472	7,498	7,518	0.1%
	-0.2%	-0.0%	0.7%	0.3%	0.3%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2023).
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 2023 - 2033

	METERED 2022	UNRESTRICTED 2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Annual Growth Rate (10 yr)
AEP	21,733	21,733	22,453	22,637	22,686	22,705	22,706	22,702	22,695	22,684	22,663	22,640	22,637	0.1%
				0.8%	0.2%	0.1%	0.0%	-0.0%	-0.0%	-0.0%	-0.1%	-0.1%	-0.0%	
APS	8,413	8,413	8,724	8,783	9,112	9,299	9,480	9,568	9,552	9,540	9,526	9,495	9,484	0.8%
				0.7%	3.7%	2.1%	1.9%	0.9%	-0.2%	-0.1%	-0.1%	-0.3%	-0.1%	
ATSI	12,772	12,781	11,962	11,929	11,892	11,858	11,840	11,828	11,805	11,756	11,702	11,636	11,593	(0.3%)
				-0.3%	-0.3%	-0.3%	-0.2%	-0.1%	-0.2%	-0.4%	-0.5%	-0.6%	-0.4%	
COMED	21,263	21,263	20,417	20,246	20,206	20,159	20,166	20,102	19,977	19,888	19,775	19,697	19,595	(0.4%)
				-0.8%	-0.2%	-0.2%	0.0%	-0.3%	-0.6%	-0.4%	-0.6%	-0.4%	-0.5%	
DAYTON	3,348	3,348	3,295	3,281	3,284	3,285	3,287	3,280	3,276	3,269	3,262	3,260	3,255	(0.1%)
				-0.4%	0.1%	0.0%	0.1%	-0.2%	-0.1%	-0.2%	-0.2%	-0.1%	-0.2%	
DEOK	5,167	5,167	5,249	5,238	5,239	5,234	5,229	5,204	5,193	5,178	5,161	5,144	5,126	(0.2%)
				-0.2%	0.0%	-0.1%	-0.1%	-0.5%	-0.2%	-0.3%	-0.3%	-0.3%	-0.3%	
DLCO	2,715	2,715	2,712	2,710	2,712	2,711	2,705	2,702	2,701	2,697	2,693	2,690	2,687	(0.1%)
				-0.1%	0.1%	-0.0%	-0.2%	-0.1%	-0.0%	-0.1%	-0.1%	-0.1%	-0.1%	
EKPC	2,107	2,107	2,027	2,036	2,049	2,054	2,061	2,063	2,069	2,071	2,078	2,079	2,084	0.3%
				0.4%	0.6%	0.2%	0.3%	0.1%	0.3%	0.1%	0.3%	0.0%	0.2%	
OVEC	121	121	95	95	95	95	95	95	95	95	95	95	95	0.0%
				0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
DIVERSITY - WESTERN(-)			1,581	1,555	1,598	1,565	1,541	1,572	1,595	1,657	1,770	1,659	1,676	
PJM WESTERN	76,307	76,412	75,353	75,400	75,677	75,835	76,028	75,972	75,768	75,521	75,185	75,077	74,880	(0.1%)
				0.1%	0.4%	0.2%	0.3%	-0.1%	-0.3%	-0.3%	-0.4%	-0.1%	-0.3%	
DOM	21,157	21,157	21,920	22,828	23,758	25,568	27,157	28,705	30,216	31,633	33,055	34,465	35,789	5.0%
				4.1%	4.1%	7.6%	6.2%	5.7%	5.3%	4.7%	4.5%	4.3%	3.8%	
DIVERSITY - TOTAL(-)			7,043	7,072	7,145	7,273	7,364	7,251	7,194	7,292	7,348	7,418	7,395	
PJM RTO	147,337	147,361	149,059	149,737	150,924	152,736	154,275	155,703	156,923	157,899	158,942	159,917	160,971	0.8%
				0.5%	0.8%	1.2%	1.0%	0.9%	0.8%	0.6%	0.7%	0.6%	0.7%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2023).
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 2034 - 2038

	2034	2035	2036	2037	2038	Annual Growth Rate (15 yr)
AEP	22,663	22,700	22,757	22,810	22,850	0.1%
	0.1%	0.2%	0.3%	0.2%	0.2%	
APS	9,478	9,482	9,499	9,503	9,520	0.6%
	-0.1%	0.0%	0.2%	0.0%	0.2%	
ATSI	11,553	11,510	11,488	11,469	11,438	(0.3%)
	-0.3%	-0.4%	-0.2%	-0.2%	-0.3%	
COMED	19,522	19,452	19,460	19,477	19,481	(0.3%)
	-0.4%	-0.4%	0.0%	0.1%	0.0%	
DAYTON	3,255	3,255	3,261	3,269	3,279	(0.0%)
	0.0%	0.0%	0.2%	0.2%	0.3%	
DEOK	5,114	5,105	5,110	5,109	5,106	(0.2%)
	-0.2%	-0.2%	0.1%	-0.0%	-0.1%	
DLCO	2,684	2,683	2,686	2,690	2,695	(0.0%)
	-0.1%	-0.0%	0.1%	0.1%	0.2%	
EKPC	2,088	2,096	2,108	2,117	2,122	0.3%
	0.2%	0.4%	0.6%	0.4%	0.2%	
OVEC	95	95	95	95	95	0.0%
	0.0%	0.0%	0.0%	0.0%	0.0%	
DIVERSITY - WESTERN(-)	1,716	1,802	1,824	1,872	1,849	
PJM WESTERN	74,736	74,576	74,640	74,667	74,737	(0.1%)
	-0.2%	-0.2%	0.1%	0.0%	0.1%	
DOM	36,980	38,115	39,255	40,443	41,741	4.4%
	3.3%	3.1%	3.0%	3.0%	3.2%	
DIVERSITY - TOTAL(-)	7,217	7,088	7,096	7,160	7,074	
PJM RTO	162,095	163,139	164,541	165,976	167,567	0.8%
	0.7%	0.6%	0.9%	0.9%	1.0%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2023).
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 2022/23 - 2032/33

	METERED 21/22	UNRESTRICTED 21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32	32/33	Annual Growth Rate (10 yr)
AE	1,515	1,515	1,590	1,585	1,582	1,583	1,583	1,587	1,579	1,573	1,568	1,568	1,561	(0.2%)
				-0.3%	-0.2%	0.1%	0.0%	0.3%	-0.5%	-0.4%	-0.3%	0.0%	-0.4%	
BGE	5,699	5,699	5,755	5,747	5,753	5,757	5,754	5,766	5,737	5,717	5,702	5,708	5,680	(0.1%)
				-0.1%	0.1%	0.1%	-0.1%	0.2%	-0.5%	-0.3%	-0.3%	0.1%	-0.5%	
DPL	3,598	3,598	3,623	3,632	3,636	3,651	3,662	3,674	3,669	3,673	3,678	3,685	3,690	0.2%
				0.2%	0.1%	0.4%	0.3%	0.3%	-0.1%	0.1%	0.1%	0.2%	0.1%	
JCPL	3,568	3,568	3,740	3,752	3,776	3,806	3,828	3,857	3,851	3,850	3,852	3,859	3,864	0.3%
				0.3%	0.6%	0.8%	0.6%	0.8%	-0.2%	-0.0%	0.1%	0.2%	0.1%	
METED	2,651	2,651	2,696	2,718	2,712	2,721	2,730	2,764	2,743	2,743	2,752	2,779	2,772	0.3%
				0.8%	-0.2%	0.3%	0.3%	1.2%	-0.8%	0.0%	0.3%	1.0%	-0.3%	
PECO	6,232	6,232	6,459	6,512	6,484	6,492	6,499	6,575	6,516	6,520	6,522	6,583	6,530	0.1%
				0.8%	-0.4%	0.1%	0.1%	1.2%	-0.9%	0.1%	0.0%	0.9%	-0.8%	
PENLC	2,831	2,831	2,823	2,824	2,809	2,802	2,797	2,802	2,784	2,773	2,767	2,768	2,751	(0.3%)
				0.0%	-0.5%	-0.2%	-0.2%	0.2%	-0.6%	-0.4%	-0.2%	0.0%	-0.6%	
PEPCO	5,085	5,085	5,381	5,408	5,422	5,445	5,474	5,508	5,489	5,498	5,507	5,538	5,531	0.3%
				0.5%	0.3%	0.4%	0.5%	0.6%	-0.3%	0.2%	0.2%	0.6%	-0.1%	
PL	7,303	7,303	7,334	7,334	7,377	7,391	7,399	7,425	7,371	7,375	7,398	7,417	7,407	0.1%
				0.0%	0.6%	0.2%	0.1%	0.4%	-0.7%	0.1%	0.3%	0.3%	-0.1%	
PS	6,409	6,409	6,530	6,533	6,524	6,520	6,516	6,515	6,486	6,455	6,431	6,411	6,393	(0.2%)
				0.0%	-0.1%	-0.1%	-0.1%	-0.0%	-0.4%	-0.5%	-0.4%	-0.3%	-0.3%	
RECO	209	209	214	220	225	231	236	240	244	246	247	249	249	1.5%
				2.8%	2.3%	2.7%	2.2%	1.7%	1.7%	0.8%	0.4%	0.8%	0.0%	
UGI	199	199	198	198	197	197	197	196	195	194	193	193	192	(0.3%)
				0.0%	-0.5%	0.0%	0.0%	-0.5%	-0.5%	-0.5%	-0.5%	0.0%	-0.5%	
DIVERSITY - MID-ATLANTIC(-)			868	754	981	916	912	777	875	910	949	872	769	
PJM MID-ATLANTIC	44,184	44,184	45,475	45,709	45,516	45,680	45,763	46,132	45,789	45,707	45,668	45,886	45,851	0.1%
				0.5%	-0.4%	0.4%	0.2%	0.8%	-0.7%	-0.2%	-0.1%	0.5%	-0.1%	
FE-EAST	8,746	8,746	9,180	9,202	9,209	9,257	9,285	9,319	9,303	9,279	9,291	9,322	9,305	0.1%
				0.2%	0.1%	0.5%	0.3%	0.4%	-0.2%	-0.3%	0.1%	0.3%	-0.2%	
PLGRP	7,501	7,501	7,525	7,524	7,570	7,584	7,592	7,617	7,556	7,569	7,589	7,608	7,594	0.1%
				-0.0%	0.6%	0.2%	0.1%	0.3%	-0.8%	0.2%	0.3%	0.3%	-0.2%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2022/23).
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 2033/34 - 2037/38

	33/34	34/35	35/36	36/37	37/38	Annual Growth Rate (15 yr)
AE	1,553	1,548	1,545	1,544	1,546	(0.2%)
	-0.5%	-0.3%	-0.2%	-0.1%	0.1%	
BGE	5,667	5,656	5,660	5,641	5,646	(0.1%)
	-0.2%	-0.2%	0.1%	-0.3%	0.1%	
DPL	3,684	3,695	3,697	3,707	3,717	0.2%
	-0.2%	0.3%	0.1%	0.3%	0.3%	
JCPL	3,851	3,844	3,849	3,862	3,881	0.2%
	-0.3%	-0.2%	0.1%	0.3%	0.5%	
METED	2,766	2,771	2,791	2,786	2,795	0.2%
	-0.2%	0.2%	0.7%	-0.2%	0.3%	
PECO	6,521	6,524	6,588	6,544	6,554	0.1%
	-0.1%	0.0%	1.0%	-0.7%	0.2%	
PENLC	2,737	2,727	2,734	2,717	2,714	(0.3%)
	-0.5%	-0.4%	0.3%	-0.6%	-0.1%	
PEPCO	5,542	5,561	5,596	5,598	5,617	0.3%
	0.2%	0.3%	0.6%	0.0%	0.3%	
PL	7,376	7,372	7,382	7,405	7,418	0.1%
	-0.4%	-0.1%	0.1%	0.3%	0.2%	
PS	6,364	6,335	6,324	6,328	6,322	(0.2%)
	-0.5%	-0.5%	-0.2%	0.1%	-0.1%	
RECO	249	249	251	254	256	1.2%
	0.0%	0.0%	0.8%	1.2%	0.8%	
UGI	191	190	189	189	189	(0.3%)
	-0.5%	-0.5%	-0.5%	0.0%	0.0%	
DIVERSITY - MID-ATLANTIC(-)	902	933	957	897	923	
PJM MID-ATLANTIC	45,599	45,539	45,649	45,678	45,732	0.0%
	-0.5%	-0.1%	0.2%	0.1%	0.1%	
FE-EAST	9,283	9,275	9,293	9,306	9,335	0.1%
	-0.2%	-0.1%	0.2%	0.1%	0.3%	
PLGRP	7,560	7,552	7,565	7,594	7,607	0.1%
	-0.4%	-0.1%	0.2%	0.4%	0.2%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2022/23).
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
2022/23 - 2032/33

	METERED 21/22	UNRESTRICTED 21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32	32/33	Annual Growth Rate (10 yr)
AEP	21,362	21,362	22,308	22,615	22,623	22,659	22,658	22,746	22,735	22,723	22,695	22,715	22,663	0.2%
				1.4%	0.0%	0.2%	-0.0%	0.4%	-0.0%	-0.1%	-0.1%	0.1%	-0.2%	
APS	9,155	9,155	8,993	9,066	9,320	9,600	9,823	10,059	10,013	10,014	10,029	10,086	10,077	1.1%
				0.8%	2.8%	3.0%	2.3%	2.4%	-0.5%	0.0%	0.1%	0.6%	-0.1%	
ATSI	9,803	9,803	9,883	9,901	9,867	9,830	9,827	9,841	9,820	9,780	9,724	9,689	9,629	(0.3%)
				0.2%	-0.3%	-0.4%	-0.0%	0.1%	-0.2%	-0.4%	-0.6%	-0.4%	-0.6%	
COMED	14,262	14,262	14,305	14,360	14,372	14,389	14,483	14,594	14,616	14,625	14,667	14,633	14,573	0.2%
				0.4%	0.1%	0.1%	0.7%	0.8%	0.2%	0.1%	0.3%	-0.2%	-0.4%	
DAYTON	2,900	2,900	2,920	2,916	2,902	2,899	2,903	2,911	2,895	2,881	2,869	2,869	2,870	(0.2%)
				-0.1%	-0.5%	-0.1%	0.1%	0.3%	-0.5%	-0.5%	-0.4%	0.0%	0.0%	
DEOK	4,388	4,388	4,479	4,467	4,463	4,462	4,452	4,466	4,440	4,425	4,408	4,396	4,380	(0.2%)
				-0.3%	-0.1%	-0.0%	-0.2%	0.3%	-0.6%	-0.3%	-0.4%	-0.3%	-0.4%	
DLCO	1,940	1,940	1,996	1,995	1,989	1,986	1,986	1,990	1,980	1,972	1,970	1,969	1,962	(0.2%)
				-0.1%	-0.3%	-0.2%	0.0%	0.2%	-0.5%	-0.4%	-0.1%	-0.1%	-0.4%	
EKPC	2,574	2,574	2,658	2,660	2,662	2,667	2,671	2,689	2,684	2,687	2,689	2,698	2,694	0.1%
				0.1%	0.1%	0.2%	0.1%	0.7%	-0.2%	0.1%	0.1%	0.3%	-0.1%	
OVEC	106	106	110	110	110	110	110	110	110	110	110	110	110	0.0%
				0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
DIVERSITY - WESTERN(-)			1,797	1,881	1,712	1,631	1,700	1,898	1,766	1,738	1,722	1,799	1,741	
PJM WESTERN	64,470	64,470	65,855	66,209	66,596	66,971	67,213	67,508	67,527	67,479	67,439	67,366	67,217	0.2%
				0.5%	0.6%	0.6%	0.4%	0.4%	0.0%	-0.1%	-0.1%	-0.1%	-0.2%	
DOM	20,229	20,229	21,625	22,480	23,234	24,678	26,122	27,689	28,960	30,362	31,735	33,170	34,488	4.8%
				4.0%	3.4%	6.2%	5.9%	6.0%	4.6%	4.8%	4.5%	4.5%	4.0%	
DIVERSITY - TOTAL(-)			4,809	4,366	4,765	4,782	4,898	4,742	5,010	4,916	4,960	4,715	5,074	
PJM RTO	128,882	128,882	130,811	132,667	133,274	135,094	136,812	139,262	139,907	141,280	142,553	144,378	144,992	1.0%
				1.4%	0.5%	1.4%	1.3%	1.8%	0.5%	1.0%	0.9%	1.3%	0.4%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2022/23).
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
2033/34 - 2037/38

	33/34	34/35	35/36	36/37	37/38	Annual Growth Rate (15 yr)
AEP	22,695	22,716	22,778	22,761	22,771	0.1%
	0.1%	0.1%	0.3%	-0.1%	0.0%	
APS	10,069	10,081	10,126	10,106	10,131	0.8%
	-0.1%	0.1%	0.4%	-0.2%	0.2%	
ATSI	9,582	9,536	9,501	9,445	9,416	(0.3%)
	-0.5%	-0.5%	-0.4%	-0.6%	-0.3%	
COMED	14,523	14,495	14,509	14,458	14,487	0.1%
	-0.3%	-0.2%	0.1%	-0.4%	0.2%	
DAYTON	2,856	2,849	2,850	2,838	2,839	(0.2%)
	-0.5%	-0.2%	0.0%	-0.4%	0.0%	
DEOK	4,362	4,349	4,349	4,328	4,315	(0.2%)
	-0.4%	-0.3%	0.0%	-0.5%	-0.3%	
DLCO	1,957	1,951	1,952	1,948	1,950	(0.2%)
	-0.3%	-0.3%	0.1%	-0.2%	0.1%	
EKPC	2,697	2,705	2,720	2,717	2,726	0.2%
	0.1%	0.3%	0.6%	-0.1%	0.3%	
OVEC	110	110	110	110	110	0.0%
	0.0%	0.0%	0.0%	0.0%	0.0%	
DIVERSITY - WESTERN(-)	1,754	1,738	1,828	1,608	1,635	
PJM WESTERN	67,097	67,054	67,067	67,103	67,110	0.1%
	-0.2%	-0.1%	0.0%	0.1%	0.0%	
DOM	35,702	36,800	37,938	38,983	40,145	4.2%
	3.5%	3.1%	3.1%	2.8%	3.0%	
DIVERSITY - TOTAL(-)	5,076	4,928	4,643	4,890	4,990	
PJM RTO	145,978	147,136	148,796	149,379	150,555	0.9%
	0.7%	0.8%	1.1%	0.4%	0.8%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2022/23).
Winter season indicates peak from December, January, February.

Table B-3

SPRING PEAK LOAD (MW) FOR
EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2023 - 2038

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
AE	1,670	1,658	1,649	1,636	1,628	1,632	1,635	1,628	1,614	1,601	1,598	1,594	1,595	1,590	1,587	1,593
BGE	5,154	5,113	5,095	5,087	5,071	5,051	5,039	5,007	4,964	4,943	4,942	4,923	4,927	4,912	4,917	4,911
DPL	3,059	3,047	3,042	3,042	3,045	3,037	3,035	3,034	3,023	3,027	3,033	3,029	3,031	3,002	3,034	3,055
JCPL	4,157	4,144	4,127	4,095	4,082	4,140	4,151	4,127	4,066	4,021	4,058	4,068	4,063	4,048	4,049	4,051
METED	2,464	2,467	2,469	2,479	2,484	2,495	2,504	2,505	2,501	2,508	2,520	2,520	2,527	2,522	2,534	2,543
PECO	6,326	6,344	6,322	6,293	6,281	6,351	6,361	6,369	6,342	6,253	6,340	6,358	6,368	6,362	6,329	6,314
PENLC	2,562	2,550	2,536	2,539	2,535	2,527	2,519	2,505	2,488	2,490	2,492	2,480	2,473	2,458	2,460	2,463
PEPCO	4,943	4,939	4,931	4,942	4,943	4,967	4,971	4,958	4,934	4,923	4,941	4,954	4,969	4,976	5,004	5,032
PL	6,379	6,373	6,350	6,382	6,417	6,408	6,411	6,400	6,359	6,409	6,409	6,402	6,384	6,352	6,385	6,427
PS	7,141	7,110	7,069	7,019	6,951	7,037	7,028	6,995	6,913	6,834	6,861	6,844	6,849	6,816	6,794	6,811
RECO	292	294	294	294	295	299	300	301	300	298	298	299	299	299	299	299
UGI	168	168	166	167	166	166	165	164	163	163	163	162	161	160	160	161
DIVERSITY - MID-ATLANTIC(-)	2,147	2,090	2,180	2,190	2,041	2,078	2,109	2,149	2,252	2,138	2,065	2,068	2,122	2,157	2,078	2,121
PJM MID-ATLANTIC	42,168	42,117	41,870	41,785	41,857	42,032	42,010	41,844	41,415	41,332	41,590	41,565	41,524	41,340	41,474	41,539
FE-EAST	8,661	8,670	8,672	8,670	8,683	8,725	8,729	8,698	8,668	8,634	8,697	8,685	8,674	8,635	8,673	8,701
PLGRP	6,543	6,537	6,513	6,544	6,577	6,571	6,573	6,561	6,516	6,568	6,570	6,560	6,543	6,508	6,544	6,585

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, 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
2023 - 2038

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
AEP	19,883	20,065	20,052	20,079	20,149	20,180	20,215	20,177	20,086	20,139	20,195	20,195	20,258	20,169	20,215	20,310
APS	7,854	7,859	8,212	8,455	8,696	8,810	8,818	8,820	8,792	8,840	8,839	8,835	8,844	8,793	8,836	8,885
ATSI	9,450	9,414	9,342	9,289	9,281	9,334	9,339	9,291	9,201	9,118	9,127	9,109	9,069	8,989	8,950	8,917
COMED	14,499	14,448	14,252	14,160	14,156	14,405	14,493	14,456	14,215	14,099	14,193	14,181	14,185	14,077	14,014	14,004
DAYTON	2,662	2,655	2,632	2,625	2,621	2,652	2,647	2,634	2,608	2,593	2,621	2,622	2,619	2,594	2,591	2,592
DEOK	4,255	4,239	4,201	4,184	4,164	4,217	4,202	4,180	4,133	4,092	4,125	4,123	4,113	4,081	4,072	4,043
DLCO	2,152	2,151	2,128	2,119	2,108	2,137	2,141	2,136	2,109	2,091	2,107	2,107	2,117	2,095	2,088	2,088
EKPC	2,098	2,105	2,116	2,122	2,129	2,152	2,138	2,148	2,151	2,155	2,159	2,165	2,164	2,176	2,183	2,195
OVEC	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
DIVERSITY - WESTERN(-)	2,395	2,544	2,443	2,346	2,369	2,421	2,497	2,663	2,550	2,548	2,431	2,402	2,424	2,472	2,381	2,501
PJM WESTERN	60,548	60,482	60,582	60,777	61,025	61,556	61,586	61,269	60,835	60,669	61,025	61,025	61,035	60,592	60,658	60,623
DOM	18,943	19,761	20,568	22,104	23,551	25,122	26,499	27,847	29,146	30,447	31,753	32,951	34,091	35,085	36,114	37,202
DIVERSITY - TOTAL(-)	6,817	6,820	6,673	6,521	6,508	7,028	7,046	7,031	6,751	6,794	6,771	6,925	7,026	6,880	6,845	6,752
PJM RTO	119,384	120,174	120,970	122,681	124,335	126,181	127,655	128,741	129,447	130,340	132,093	133,086	134,170	134,766	135,860	137,234

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, 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
2023 - 2038

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
AE	1,971	1,975	1,977	1,967	1,957	1,935	1,928	1,926	1,929	1,916	1,908	1,895	1,884	1,898	1,894	1,897
BGE	5,344	5,332	5,336	5,327	5,298	5,265	5,242	5,216	5,190	5,160	5,133	5,112	5,099	5,108	5,112	5,108
DPL	3,132	3,109	3,118	3,104	3,096	3,085	3,065	3,055	3,041	3,031	3,017	2,988	2,995	3,019	3,027	3,026
JCPL	4,684	4,698	4,724	4,720	4,703	4,667	4,659	4,665	4,664	4,653	4,617	4,599	4,596	4,649	4,663	4,675
METED	2,543	2,564	2,577	2,587	2,589	2,585	2,594	2,606	2,616	2,621	2,619	2,619	2,625	2,654	2,667	2,677
PECO	6,932	6,978	7,005	7,016	7,006	6,976	6,981	7,026	7,043	7,038	7,021	7,010	7,012	7,090	7,112	7,109
PENLC	2,522	2,510	2,513	2,517	2,511	2,496	2,481	2,481	2,480	2,480	2,472	2,458	2,443	2,459	2,460	2,459
PEPCO	5,198	5,222	5,262	5,282	5,289	5,285	5,276	5,293	5,292	5,266	5,261	5,264	5,280	5,316	5,348	5,377
PL	6,205	6,207	6,240	6,268	6,266	6,251	6,247	6,253	6,267	6,284	6,275	6,266	6,253	6,294	6,342	6,363
PS	8,000	8,009	8,029	8,013	7,959	7,897	7,844	7,871	7,884	7,862	7,799	7,745	7,722	7,797	7,820	7,829
RECO	319	324	329	331	331	329	329	333	334	332	330	327	326	333	335	337
UGI	165	164	164	165	164	163	162	161	161	161	160	159	159	158	159	158
DIVERSITY - MID-ATLANTIC(-)	1,247	1,046	1,044	1,035	1,069	1,227	1,138	1,178	1,236	1,327	1,301	1,373	1,370	1,252	1,295	1,309
PJM MID-ATLANTIC	45,768	46,046	46,230	46,262	46,100	45,707	45,670	45,708	45,665	45,477	45,311	45,069	45,024	45,523	45,644	45,706
FE-EAST	9,482	9,580	9,649	9,663	9,604	9,485	9,490	9,549	9,568	9,525	9,469	9,426	9,423	9,535	9,567	9,578
PLGRP	6,365	6,369	6,401	6,428	6,423	6,409	6,407	6,411	6,423	6,438	6,432	6,419	6,410	6,448	6,496	6,515

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, 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
2023 - 2038

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
AEP	20,233	20,405	20,567	20,610	20,595	20,551	20,446	20,493	20,627	20,558	20,584	20,580	20,491	20,743	20,805	20,783
APS	7,676	7,839	8,171	8,388	8,589	8,607	8,592	8,592	8,606	8,609	8,604	8,598	8,575	8,609	8,641	8,653
ATSI	10,270	10,233	10,361	10,331	10,325	10,168	10,142	10,107	10,209	10,163	10,050	9,929	9,891	10,028	10,010	9,986
COMED	17,269	17,139	17,158	17,257	17,178	17,034	16,931	16,906	16,907	16,865	16,751	16,695	16,503	16,724	16,790	16,812
DAYTON	2,885	2,883	2,908	2,915	2,912	2,880	2,849	2,871	2,888	2,888	2,879	2,861	2,830	2,891	2,903	2,901
DEOK	4,689	4,677	4,704	4,697	4,682	4,656	4,617	4,620	4,629	4,601	4,588	4,565	4,541	4,585	4,577	4,567
DLCO	2,347	2,348	2,357	2,360	2,355	2,341	2,334	2,335	2,342	2,342	2,332	2,320	2,316	2,335	2,339	2,343
EKPC	1,980	1,965	1,975	1,992	2,009	2,026	2,031	2,007	2,012	2,032	2,047	2,057	2,064	2,047	2,059	2,074
OVEC	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
DIVERSITY - WESTERN(-)	1,870	2,073	2,076	1,923	2,097	1,864	2,020	2,003	2,149	2,036	2,065	2,077	2,122	2,266	2,232	2,221
PJM WESTERN	65,559	65,496	66,205	66,707	66,628	66,479	66,002	66,008	66,151	66,102	65,850	65,608	65,169	65,776	65,972	65,978
DOM	19,468	20,316	21,343	23,177	24,794	26,321	27,795	29,213	30,775	32,146	33,481	34,689	35,823	37,018	38,240	39,575
DIVERSITY - TOTAL(-)	6,155	6,193	5,992	5,945	5,758	6,089	6,397	6,364	6,262	6,073	6,401	6,680	6,758	6,674	6,612	6,561
PJM RTO	127,757	128,784	130,906	133,159	134,930	135,509	136,228	137,746	139,714	141,015	141,607	142,136	142,750	145,161	146,771	148,228

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

Table B-5

MONTHLY PEAK FORECAST SCALED to SEASONAL PEAK (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 2023	1,590	5,755	3,623	3,740	2,696	6,459	2,823	5,381	7,334	6,530	214	198	868	45,475
Feb 2023	1,494	5,415	3,413	3,494	2,560	6,052	2,691	4,985	7,008	6,164	201	186	552	43,111
Mar 2023	1,354	4,970	3,059	3,167	2,439	5,501	2,562	4,594	6,379	5,707	186	168	610	39,476
Apr 2023	1,246	4,151	2,426	2,883	2,152	4,946	2,309	3,909	5,414	5,234	186	142	1,011	33,987
May 2023	1,670	5,154	2,953	4,157	2,464	6,326	2,345	4,943	5,708	7,141	292	146	1,131	42,168
Jun 2023	2,283	6,088	3,581	5,724	2,901	8,171	2,743	5,717	6,771	9,391	403	181	1,691	52,263
Jul 2023	2,549	6,474	3,861	6,072	3,040	8,527	2,871	6,166	7,175	9,904	414	195	1,512	55,736
Aug 2023	2,414	6,324	3,738	5,797	2,960	8,110	2,730	6,005	6,866	9,481	395	181	1,550	53,451
Sep 2023	1,971	5,344	3,132	4,684	2,543	6,932	2,522	5,198	6,205	8,000	319	165	1,247	45,768
Oct 2023	1,419	4,068	2,385	3,216	2,084	5,131	2,285	3,981	5,298	5,891	209	143	1,194	34,916
Nov 2023	1,340	4,351	2,659	3,187	2,254	5,298	2,459	4,111	5,951	5,680	196	165	619	37,032
Dec 2023	1,532	5,177	3,240	3,654	2,567	6,105	2,675	4,856	6,767	6,324	216	188	196	43,105

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	DIVERSITY	MID-ATLANTIC
Jan 2024	1,585	5,747	3,632	3,752	2,718	6,512	2,824	5,408	7,334	6,533	220	198	754	45,709
Feb 2024	1,509	5,458	3,460	3,548	2,632	6,227	2,745	5,057	7,080	6,219	208	188	400	43,931
Mar 2024	1,347	4,948	3,047	3,178	2,434	5,473	2,550	4,556	6,373	5,701	191	168	529	39,437
Apr 2024	1,250	4,188	2,493	2,932	2,201	4,972	2,336	3,975	5,533	5,269	191	144	747	34,737
May 2024	1,658	5,113	2,934	4,144	2,467	6,344	2,337	4,939	5,750	7,110	294	146	1,119	42,117
Jun 2024	2,251	6,005	3,534	5,624	2,879	8,076	2,705	5,663	6,716	9,198	401	179	1,890	51,341
Jul 2024	2,526	6,428	3,841	6,032	3,041	8,522	2,858	6,164	7,181	9,824	415	194	1,576	55,450
Aug 2024	2,398	6,277	3,711	5,749	2,957	8,085	2,706	5,970	6,848	9,413	395	180	1,630	53,059
Sep 2024	1,975	5,332	3,109	4,698	2,564	6,978	2,510	5,222	6,207	8,009	324	164	1,046	46,046
Oct 2024	1,422	4,107	2,391	3,264	2,101	5,215	2,275	4,084	5,308	5,931	217	142	1,265	35,192
Nov 2024	1,326	4,314	2,620	3,164	2,225	5,223	2,424	4,082	5,892	5,633	199	161	607	36,656
Dec 2024	1,533	5,190	3,242	3,688	2,554	6,095	2,664	4,884	6,821	6,341	222	189	405	43,018

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	DIVERSITY	MID-ATLANTIC
Jan 2025	1,582	5,753	3,636	3,776	2,712	6,484	2,809	5,422	7,377	6,524	225	197	981	45,516
Feb 2025	1,488	5,411	3,407	3,520	2,566	6,050	2,671	5,040	6,994	6,150	211	185	693	43,000
Mar 2025	1,349	4,968	3,042	3,228	2,457	5,477	2,536	4,547	6,350	5,683	198	166	476	39,525
Apr 2025	1,250	4,208	2,482	2,984	2,230	4,987	2,325	4,003	5,535	5,264	196	143	659	34,948
May 2025	1,649	5,095	2,885	4,127	2,469	6,322	2,304	4,931	5,653	7,069	294	144	1,072	41,870
Jun 2025	2,250	5,992	3,530	5,622	2,905	8,119	2,716	5,713	6,747	9,215	404	180	1,626	51,767
Jul 2025	2,516	6,406	3,823	6,025	3,058	8,533	2,863	6,194	7,212	9,795	417	194	1,617	55,419
Aug 2025	2,395	6,244	3,682	5,725	2,967	8,085	2,705	5,998	6,845	9,396	397	180	1,643	52,976
Sep 2025	1,977	5,336	3,118	4,724	2,577	7,005	2,513	5,262	6,240	8,029	329	164	1,044	46,230
Oct 2025	1,424	4,104	2,379	3,295	2,105	5,223	2,261	4,106	5,314	5,925	219	141	1,198	35,298
Nov 2025	1,325	4,331	2,620	3,192	2,220	5,233	2,404	4,101	5,880	5,627	204	160	720	36,577
Dec 2025	1,537	5,215	3,262	3,747	2,574	6,117	2,662	4,945	6,855	6,352	229	189	435	43,249

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.

Table B-5

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

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	OVEC	WESTERN DIVERSITY	PJM WESTERN	DOM	TOTAL DIVERSITY	PJM RTO
Jan 2023	22,308	8,993	9,883	14,305	2,920	4,479	1,996	2,658	100	1,787	65,855	21,625	4,799	130,811
Feb 2023	21,218	8,541	9,446	13,582	2,753	4,190	1,895	2,424	110	1,699	62,460	20,035	4,781	123,076
Mar 2023	19,883	7,854	8,910	12,206	2,554	3,798	1,764	2,098	90	-521	59,678	18,909	968	117,184
Apr 2023	17,242	6,671	8,061	11,192	2,250	3,372	1,641	1,655	80	-176	52,340	16,189	2,224	101,127
May 2023	18,900	7,160	9,450	14,499	2,662	4,255	2,152	1,621	70	221	60,548	18,943	3,627	119,384
Jun 2023	21,421	8,360	11,577	19,756	3,152	5,016	2,611	1,916	75	2,071	71,813	20,839	8,212	140,465
Jul 2023	22,453	8,724	11,962	20,417	3,295	5,249	2,712	2,027	95	1,581	75,353	21,920	7,043	149,059
Aug 2023	22,057	8,640	11,764	20,384	3,266	5,216	2,684	2,004	75	1,984	74,106	21,365	6,227	146,229
Sep 2023	20,233	7,676	10,270	17,269	2,885	4,689	2,347	1,792	70	1,672	65,559	19,468	5,957	127,757
Oct 2023	16,839	6,545	7,990	12,344	2,268	3,611	1,737	1,595	70	2,023	50,976	16,285	5,213	100,181
Nov 2023	18,422	7,360	8,543	12,162	2,405	3,585	1,735	1,980	80	1,379	54,893	17,746	3,902	107,767
Dec 2023	20,589	8,256	9,485	13,849	2,677	4,104	1,919	2,353	90	1,870	61,452	20,154	4,459	122,318

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	OVEC	DIVERSITY	WESTERN	DOM	DIVERSITY	PJM RTO
Jan 2024	22,615	9,066	9,901	14,360	2,916	4,467	1,995	2,660	100	1,871	66,209	22,480	4,356	132,667
Feb 2024	21,851	8,755	9,625	13,842	2,794	4,244	1,921	2,463	110	1,838	63,767	21,081	4,380	126,637
Mar 2024	20,065	7,859	8,858	12,202	2,547	3,794	1,758	2,105	90	-252	59,530	19,582	1,171	117,655
Apr 2024	17,760	6,781	8,110	11,255	2,280	3,416	1,650	1,697	80	152	52,877	17,107	2,412	103,208
May 2024	19,085	7,156	9,414	14,448	2,655	4,239	2,151	1,612	70	348	60,482	19,761	3,653	120,174
Jun 2024	21,393	8,305	11,359	19,329	3,083	4,951	2,587	1,913	75	1,938	71,057	21,705	7,598	140,333
Jul 2024	22,637	8,783	11,929	20,246	3,281	5,238	2,710	2,036	95	1,555	75,400	22,828	7,072	149,737
Aug 2024	22,137	8,665	11,684	20,179	3,217	5,183	2,670	2,006	75	1,835	73,981	22,266	7,324	145,447
Sep 2024	20,405	7,839	10,233	17,139	2,883	4,677	2,348	1,807	70	1,905	65,496	20,316	6,025	128,784
Oct 2024	17,065	6,751	8,033	12,441	2,278	3,632	1,741	1,620	70	2,113	51,518	17,195	5,222	102,061
Nov 2024	18,508	7,500	8,463	12,183	2,379	3,534	1,707	1,965	80	1,383	54,936	18,466	4,058	107,990
Dec 2024	20,749	8,491	9,509	13,918	2,668	4,108	1,921	2,361	90	1,459	62,356	21,068	4,460	123,846

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	OVEC	DIVERSITY	WESTERN	DOM	DIVERSITY	PJM RTO
Jan 2025	22,623	9,320	9,867	14,372	2,902	4,463	1,989	2,662	100	1,702	66,596	23,234	4,755	133,274
Feb 2025	21,452	8,899	9,401	13,634	2,737	4,175	1,882	2,431	110	1,834	62,887	21,518	4,669	125,263
Mar 2025	20,052	8,212	8,852	12,249	2,536	3,777	1,755	2,116	90	-433	60,072	20,452	461	119,631
Apr 2025	17,776	7,155	8,085	11,282	2,277	3,412	1,648	1,710	80	-143	53,568	18,013	1,491	105,554
May 2025	19,014	7,475	9,342	14,252	2,632	4,201	2,128	1,617	70	149	60,582	20,568	3,271	120,970
Jun 2025	21,531	8,654	11,391	19,303	3,090	4,949	2,598	1,931	75	1,877	71,645	22,623	7,381	142,157
Jul 2025	22,686	9,112	11,892	20,206	3,284	5,239	2,712	2,049	95	1,598	75,677	23,758	7,145	150,924
Aug 2025	22,155	8,974	11,574	19,944	3,202	5,159	2,668	2,018	75	1,596	74,173	23,198	6,890	146,696
Sep 2025	20,567	8,171	10,361	17,158	2,908	4,704	2,357	1,827	70	1,918	66,205	21,343	5,834	130,906
Oct 2025	17,109	7,045	7,951	12,437	2,279	3,620	1,741	1,633	70	2,040	51,845	18,207	5,086	103,502
Nov 2025	18,555	7,769	8,371	12,147	2,376	3,522	1,705	1,975	80	1,323	55,177	19,384	4,037	109,144
Dec 2025	20,847	8,818	9,481	13,965	2,674	4,112	1,923	2,374	90	1,411	62,873	22,248	4,510	125,706

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.

Table B-6

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

	FE_EAST	PLGRP
Jan 2023	9,180	7,525
Feb 2023	8,645	7,188
Mar 2023	8,006	6,543
Apr 2023	7,153	5,553
May 2023	8,661	5,854
Jun 2023	11,079	6,951
Jul 2023	11,696	7,370
Aug 2023	11,243	7,047
Sep 2023	9,482	6,365
Oct 2023	7,336	5,436
Nov 2023	7,806	6,114
Dec 2023	8,822	6,946

	FE_EAST	PLGRP
Jan 2024	9,202	7,524
Feb 2024	8,823	7,275
Mar 2024	7,986	6,537
Apr 2024	7,242	5,672
May 2024	8,670	5,889
Jun 2024	10,925	6,894
Jul 2024	11,673	7,379
Aug 2024	11,202	7,030
Sep 2024	9,580	6,369
Oct 2024	7,399	5,445
Nov 2024	7,721	6,041
Dec 2024	8,859	7,007

	FE_EAST	PLGRP
Jan 2025	9,209	7,570
Feb 2025	8,685	7,174
Mar 2025	8,097	6,513
Apr 2025	7,346	5,674
May 2025	8,672	5,795
Jun 2025	10,989	6,926
Jul 2025	11,686	7,407
Aug 2025	11,198	7,024
Sep 2025	9,649	6,401
Oct 2025	7,445	5,449
Nov 2025	7,750	6,033
Dec 2025	8,917	7,044

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
FE_EAST contains JCPL, METED and PENLC zones. PLGRP contains PL and UGI zones.

Table B-7

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

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
AE																
CAPACITY PERFORMANCE	39	38	38	38	38	38	37	37	37	37	37	36	36	36	36	36
SUMMER PERIOD	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	47	46	46	46	46	46	45	45	45	45	45	44	44	44	44	44
BGE																
CAPACITY PERFORMANCE	83	82	82	81	81	80	80	79	79	78	77	77	76	76	76	76
SUMMER PERIOD	77	77	77	76	76	75	75	74	74	73	72	72	71	71	71	71
PRD	87	132	132	131	130	130	128	127	127	125	124	123	123	123	123	123
TOTAL LOAD MANAGEMENT	247	291	291	288	287	285	283	280	280	276	273	272	270	270	270	270
DPL																
CAPACITY PERFORMANCE	82	82	81	81	81	80	80	79	79	78	78	78	78	78	78	78
SUMMER PERIOD	100	99	99	98	98	97	97	96	96	95	95	94	94	94	94	94
PRD	38	50	50	50	50	49	49	49	48	48	48	48	48	48	48	48
TOTAL LOAD MANAGEMENT	220	231	230	229	229	226	226	224	223	221	221	220	220	220	220	220
JCPL																
CAPACITY PERFORMANCE	93	92	92	92	91	91	90	90	89	89	89	89	88	89	89	89
SUMMER PERIOD	8	8	8	8	8	8	8	8	8	8	8	7	7	8	8	8
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	101	100	100	100	99	99	98	98	97	97	97	96	95	97	97	97
METED																
CAPACITY PERFORMANCE	140	140	141	141	142	142	142	142	143	143	143	143	144	144	145	146
SUMMER PERIOD	26	26	26	26	26	26	26	26	26	26	26	26	26	26	27	28
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	166	166	167	167	168	168	168	168	169	169	169	169	170	170	172	174

Notes:
Summer-Period DR refers to DR resources that aggregate with Winter-Period resources to form a year-round commitment.
Forecast values for Capacity Performance and Summer-Period DR are based on actual committed quantities for Delivery Years 2020/21, 2021/22, 2022/23; forecast values for PRD are based on actual cleared quantities in the 2021/22, 2022/23 and 2023/24 RPM Base Residual Auctions

Table B-7 (Continued)

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

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
PECO																
CAPACITY PERFORMANCE	247	246	247	247	247	248	248	248	248	248	248	248	248	249	250	251
SUMMER PERIOD	27	27	27	27	27	28	27	27	28	28	28	28	28	28	28	28
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	274	273	274	274	274	276	275	275	276	276	276	276	276	277	278	279
PENLC																
CAPACITY PERFORMANCE	149	148	149	148	148	147	146	146	146	145	145	144	144	144	144	144
SUMMER PERIOD	81	81	81	81	80	80	80	80	79	79	79	78	78	78	78	78
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	230	229	230	229	228	227	226	226	225	224	224	222	222	222	222	222
PEPCO																
CAPACITY PERFORMANCE	91	91	92	92	92	92	92	92	92	92	92	92	92	93	93	93
SUMMER PERIOD	139	139	139	140	140	140	140	140	140	139	139	139	139	140	141	142
PRD	110	140	141	141	141	141	141	141	141	141	141	141	141	142	142	142
TOTAL LOAD MANAGEMENT	340	370	372	373	373	373	373	373	373	372	372	372	372	375	376	377
PL																
CAPACITY PERFORMANCE	320	321	322	323	322	322	322	322	323	323	323	323	323	325	326	327
SUMMER PERIOD	115	115	115	116	116	116	115	115	116	116	116	116	116	116	117	118
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	435	436	437	439	438	438	437	437	439	439	439	439	439	441	443	445
PS																
CAPACITY PERFORMANCE	134	133	133	133	132	131	131	130	130	129	129	129	127	128	129	130
SUMMER PERIOD	72	72	71	71	71	71	70	70	70	69	69	69	68	69	69	69
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	206	205	204	204	203	202	201	200	200	198	198	198	195	197	198	199

Notes:
Summer-Period DR refers to DR resources that aggregate with Winter-Period resources to form a year-round commitment.
Forecast values for Capacity Performance and Summer-Period DR are based on actual committed quantities for Delivery Years 2020/21, 2021/22, 2022/23; forecast values for PRD are based on actual cleared quantities in the 2021/22, 2022/23 and 2023/24 RPM Base Residual Auctions

Table B-7 (Continued)

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

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
RECO																
CAPACITY PERFORMANCE	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
SUMMER PERIOD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
UGI																
CAPACITY PERFORMANCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUMMER PERIOD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PJM MID-ATLANTIC																
CAPACITY PERFORMANCE	1,380	1,375	1,379	1,378	1,376	1,373	1,370	1,367	1,368	1,364	1,363	1,361	1,358	1,364	1,368	1,372
SUMMER PERIOD	653	652	651	651	650	649	646	644	645	641	640	637	635	638	641	644
PRD	235	322	323	322	321	320	318	317	316	314	313	312	312	313	313	313
TOTAL LOAD MANAGEMENT	2,268	2,349	2,353	2,351	2,347	2,342	2,334	2,328	2,329	2,319	2,316	2,310	2,305	2,315	2,322	2,329

Notes:
Summer-Period DR refers to DR resources that aggregate with Winter-Period resources to form a year-round commitment.
Forecast values for Capacity Performance and Summer-Period DR are based on actual committed quantities for Delivery Years 2020/21, 2021/22, 2022/23; forecast values for PRD are based on actual cleared quantities in the 2021/22, 2022/23 and 2023/24 RPM Base Residual Auctions

Table B-7 (Continued)

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

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
AEP																
CAPACITY PERFORMANCE	854	861	863	864	864	864	863	863	862	861	861	862	864	866	868	870
SUMMER PERIOD	288	290	291	291	291	291	291	291	291	290	290	291	291	292	293	294
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	1,142	1,151	1,154	1,155	1,155	1,155	1,154	1,154	1,153	1,151	1,151	1,153	1,155	1,158	1,161	1,164
APS																
CAPACITY PERFORMANCE	418	421	436	445	454	458	457	457	456	455	454	454	454	455	455	455
SUMMER PERIOD	125	126	131	134	136	137	137	137	137	136	136	136	136	137	137	137
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	543	547	567	579	590	595	594	594	593	591	590	590	590	592	592	592
ATSI																
CAPACITY PERFORMANCE	540	538	537	535	534	534	533	531	528	525	523	521	520	519	518	517
SUMMER PERIOD	161	160	160	159	159	159	158	158	157	156	156	155	154	154	154	154
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	701	698	697	694	693	693	691	689	685	681	679	676	674	673	672	671
COMED																
CAPACITY PERFORMANCE	1,023	1,014	1,012	1,010	1,010	1,007	1,001	996	991	987	981	978	974	975	976	977
SUMMER PERIOD	328	326	325	324	324	323	321	320	318	317	315	314	313	313	313	313
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	1,351	1,340	1,337	1,334	1,334	1,330	1,322	1,316	1,309	1,304	1,296	1,292	1,287	1,288	1,289	1,290
DAYTON																
CAPACITY PERFORMANCE	106	106	106	106	106	106	106	106	105	105	105	105	105	105	106	107
SUMMER PERIOD	58	58	58	58	58	58	58	58	57	57	57	57	57	57	58	59
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	164	164	164	164	164	164	164	164	162	162	162	162	162	162	164	166

Notes:
Summer-Period DR refers to DR resources that aggregate with Winter-Period resources to form a year-round commitment.
Forecast values for Capacity Performance and Summer-Period DR are based on actual committed quantities for Delivery Years 2020/21, 2021/22, 2022/23; forecast values for PRD are based on actual cleared quantities in the 2021/22, 2022/23 and 2023/24 RPM Base Residual Auctions

Table B-7 (Continued)

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

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
DEOK																
CAPACITY PERFORMANCE	113	113	113	113	113	112	112	112	111	111	110	110	110	110	110	110
SUMMER PERIOD	40	40	40	40	40	40	40	40	40	39	39	39	39	39	39	39
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	153	153	153	153	153	152	152	152	151	150	149	149	149	149	149	149
DLCO																
CAPACITY PERFORMANCE	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
SUMMER PERIOD	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88
EKPC																
CAPACITY PERFORMANCE	94	95	96	96	96	96	96	97	97	97	97	97	98	98	99	100
SUMMER PERIOD	80	80	81	81	81	81	81	81	82	82	82	82	82	83	83	83
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	174	175	177	177	177	177	177	178	179	179	179	179	180	181	182	183
PJM WESTERN																
CAPACITY PERFORMANCE	3,208	3,208	3,223	3,229	3,237	3,237	3,228	3,222	3,210	3,201	3,191	3,187	3,185	3,188	3,192	3,196
SUMMER PERIOD	1,108	1,108	1,114	1,115	1,117	1,117	1,114	1,113	1,110	1,105	1,103	1,102	1,100	1,103	1,105	1,107
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	4,316	4,316	4,337	4,344	4,354	4,354	4,342	4,335	4,320	4,306	4,294	4,289	4,285	4,291	4,297	4,303

Notes:
Summer-Period DR refers to DR resources that aggregate with Winter-Period resources to form a year-round commitment.
Forecast values for Capacity Performance and Summer-Period DR are based on actual committed quantities for Delivery Years 2020/21, 2021/22, 2022/23; forecast values for PRD are based on actual cleared quantities in the 2021/22, 2022/23 and 2023/24 RPM Base Residual Auctions

Table B-7 (Continued)

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

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
DOM																
CAPACITY PERFORMANCE	601	625	651	700	744	786	828	867	906	944	980	1,013	1,044	1,075	1,108	1,142
SUMMER PERIOD	103	107	112	120	128	135	142	149	155	162	168	174	179	185	190	195
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	704	732	763	820	872	921	970	1,016	1,061	1,106	1,148	1,187	1,223	1,260	1,298	1,337
PJM RTO																
CAPACITY PERFORMANCE	5,189	5,208	5,253	5,307	5,357	5,396	5,426	5,456	5,484	5,509	5,534	5,561	5,587	5,627	5,668	5,709
SUMMER PERIOD	1,864	1,867	1,877	1,886	1,895	1,901	1,902	1,906	1,910	1,908	1,911	1,913	1,914	1,926	1,936	1,946
PRD	235	322	323	322	321	320	318	317	316	314	313	312	312	313	313	313
TOTAL LOAD MANAGEMENT	7,288	7,397	7,453	7,515	7,573	7,617	7,646	7,679	7,710	7,731	7,758	7,786	7,813	7,866	7,917	7,968

Notes:
Summer-Period DR refers to DR resources that aggregate with Winter-Period resources to form a year-round commitment.
Forecast values for Capacity Performance and Summer-Period DR are based on actual committed quantities for Delivery Years 2020/21, 2021/22, 2022/23; forecast values for PRD are based on actual cleared quantities in the 2021/22, 2022/23 and 2023/24 RPM Base Residual Auctions

Table B-8a

DISTRIBUTED SOLAR ADJUSTMENTS TO SUMMER PEAK LOAD (MW) FOR EACH PJM ZONE AND RTO
2023 - 2038

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
AE	136	125	117	109	109	113	111	111	106	100	97	95	96	89	86	85
BGE	194	211	223	242	250	267	286	290	273	256	249	243	239	233	223	220
DPL	103	112	121	125	129	126	125	133	136	130	124	123	116	110	107	102
JCPL	261	271	281	289	300	305	304	308	317	329	329	328	326	332	327	318
METED	46	51	53	55	58	61	64	66	69	72	74	76	79	78	79	80
PECO	68	84	92	99	109	121	133	144	157	169	177	185	196	203	210	216
PENLC	19	28	33	37	43	49	56	62	67	73	77	81	84	85	87	88
PEPCO	214	229	249	263	280	294	304	298	289	279	282	287	289	283	278	283
PL	114	128	133	138	147	153	161	171	178	186	193	198	206	211	218	220
PS	392	408	418	423	424	404	415	406	413	372	365	364	374	360	352	338
RECO	13	14	16	18	18	19	21	22	23	24	25	25	26	26	25	24
UGI	1	1	1	1	1	2	2	2	2	3	3	3	3	3	3	3
AEP	134	180	198	214	233	253	277	297	311	332	343	355	369	370	381	390
APS	86	99	107	112	121	130	137	145	154	166	169	171	174	181	187	187
ATSI	102	133	143	151	160	171	178	185	190	197	205	212	215	217	222	229
COMED	323	412	476	531	557	603	656	701	767	813	836	869	887	899	902	917
DAYTON	26	36	38	39	42	44	47	50	52	53	55	57	59	61	62	64
DEOK	23	35	38	41	45	48	53	58	61	64	67	69	73	76	80	83
DLCO	20	25	27	29	32	36	40	44	48	51	54	56	58	59	61	63
EKPC	5	5	5	6	7	8	9	11	12	13	14	15	16	17	19	20
OVEC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DOM	527	536	539	565	578	610	634	671	698	699	718	750	768	795	795	823
PJM RTO	2,888	3,269	3,566	3,841	4,035	4,185	4,362	4,467	4,626	4,613	4,610	4,600	4,685	4,611	4,547	4,614

Notes:
Adjustment values presented here are average summer peak distribution forecast values.

Table B-8b

PLUG IN ELECTRIC VEHICLE ADJUSTMENT TO SUMMER PEAK LOAD (MW) FOR EACH PJM ZONE AND RTO
2023 - 2038

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
AE	5	10	17	24	29	32	35	37	38	39	38	37	36	38	40	42
BGE	9	21	35	49	61	72	79	85	91	94	95	93	91	97	102	108
DPL	2	4	7	9	11	13	15	16	17	17	18	18	18	19	21	22
JCPL	17	37	61	84	104	120	134	142	149	151	151	149	144	153	162	170
METED	1	2	2	3	4	4	5	5	5	6	6	6	6	7	7	8
PECO	3	6	9	11	13	15	17	19	20	21	22	22	23	25	27	29
PENLC	1	1	2	3	3	4	4	5	5	6	6	6	7	7	8	8
PEPCO	13	29	49	68	85	102	117	131	144	155	162	166	169	182	191	200
PL	1	2	3	4	5	5	6	6	7	7	8	8	8	8	9	10
PS	14	31	51	70	87	102	113	120	125	128	129	127	123	131	139	146
RECO	3	6	11	15	19	22	24	26	27	28	28	27	27	29	30	32
UGI	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AEP	5	10	16	22	27	31	34	38	40	42	43	43	43	47	51	55
APS	3	7	12	16	20	23	26	28	29	30	30	30	29	32	34	36
ATSI	3	7	10	12	15	17	19	20	22	23	23	24	24	26	28	30
COMED	22	51	87	128	179	233	291	364	386	376	367	353	336	353	368	383
DAYTON	1	1	2	3	3	3	4	4	4	4	5	5	5	5	6	6
DEOK	1	2	3	4	5	6	6	7	7	7	7	7	7	8	9	10
DLCO	1	1	2	3	3	4	4	5	5	5	5	5	5	6	6	7
EKPC	0	1	1	2	2	2	2	3	3	3	3	3	3	3	3	4
OVEC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DOM	26	62	107	151	191	223	252	276	291	301	304	301	295	314	333	348
PJM RTO	134	297	486	677	857	1,032	1,184	1,338	1,423	1,462	1,478	1,461	1,415	1,520	1,616	1,697

Notes:
Adjustment values presented here are average summer peak distribution forecast values.

Table B-9

ADJUSTMENTS ABOVE EMBEDDED TO SUMMER PEAK LOAD (MW) FOR EACH PJM ZONE AND RTO
2023 - 2038

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
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	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
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	90	248	248	248	248	248	248	248	248	248	248	248	248	248	248	248
APS	1	85	409	597	785	856	856	856	856	856	856	856	856	856	856	856
ATSI	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
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	-8	-8	-8	-8	-8	-8	-8	-8	-8	-8	-8	-8	-8	-8	-8	-8
DOM	2,068	2,988	3,926	5,678	7,196	8,690	10,160	11,586	13,016	14,426	15,717	16,878	17,962	19,030	20,124	21,310
PJM RTO	2,231	3,393	4,654	6,594	8,300	9,866	11,336	12,762	14,192	15,602	16,893	18,054	19,139	20,206	21,300	22,486

Notes:
Adjustment values presented here are reflected in summer peak forecasts.
Adjustments due to NRBTMG (Non-Retail Behind the Meter Generation) transitioning to DR are in AEP, ATSI and PL.
Adjustments due to data center load growth are in AEP, APS, and DOM.
An adjustment due to peak shaving program is in EKPC.
Adjustment shown for DOM is reflective of data center load in addition to what is already embedded.
PJM RTO is sum of adjustments shown.

Table B-10

SUMMER COINCIDENT PEAK LOAD (MW) FOR
EACH PJM ZONE, LOCATIONAL DELIVERABILITY AREA AND RTO
2023 - 2038

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
AE	2,296	2,268	2,262	2,253	2,241	2,231	2,221	2,210	2,201	2,198	2,194	2,191	2,186	2,186	2,193	2,191
BGE	6,232	6,191	6,179	6,149	6,111	6,065	6,026	5,973	5,930	5,878	5,846	5,818	5,800	5,787	5,778	5,766
DPL	3,637	3,601	3,578	3,559	3,532	3,514	3,497	3,468	3,442	3,418	3,400	3,390	3,394	3,402	3,412	3,410
JCPL	5,692	5,646	5,637	5,621	5,587	5,576	5,554	5,525	5,503	5,482	5,477	5,469	5,465	5,473	5,508	5,515
METED	2,918	2,923	2,932	2,941	2,944	2,948	2,955	2,959	2,963	2,965	2,971	2,979	2,993	3,002	3,017	3,031
PECO	8,037	8,034	8,047	8,047	8,035	8,023	8,015	7,995	7,974	7,945	7,938	7,941	7,969	7,968	7,988	8,009
PENLC	2,745	2,731	2,727	2,723	2,713	2,704	2,695	2,687	2,680	2,676	2,670	2,665	2,663	2,665	2,670	2,673
PEPCO	5,895	5,894	5,914	5,933	5,939	5,947	5,952	5,942	5,936	5,922	5,922	5,938	5,957	5,985	6,011	6,042
PL	6,881	6,878	6,899	6,914	6,909	6,905	6,906	6,907	6,907	6,908	6,916	6,918	6,939	6,956	6,987	7,014
PS	9,335	9,258	9,214	9,163	9,088	9,049	9,000	8,933	8,878	8,832	8,821	8,805	8,800	8,803	8,844	8,847
RECO	388	388	390	392	392	392	392	390	389	387	386	385	384	385	388	390
UGI	184	184	183	183	182	181	180	179	178	178	177	176	176	175	175	175
AEP	21,837	22,007	22,042	22,081	22,106	22,100	22,089	22,058	22,053	22,061	22,052	22,076	22,106	22,197	22,262	22,365
APS	8,531	8,602	8,927	9,124	9,305	9,382	9,374	9,355	9,338	9,332	9,326	9,325	9,324	9,324	9,335	9,360
ATSI	11,591	11,527	11,481	11,450	11,443	11,429	11,389	11,329	11,273	11,249	11,202	11,159	11,113	11,109	11,102	11,103
COMED	18,866	18,790	18,771	18,688	18,670	18,661	18,593	18,560	18,426	18,246	18,137	18,060	17,925	18,020	18,004	18,012
DAYTON	3,104	3,094	3,089	3,094	3,097	3,085	3,077	3,072	3,060	3,069	3,062	3,062	3,062	3,068	3,077	3,095
DEOK	5,001	4,982	4,973	4,968	4,971	4,960	4,946	4,919	4,893	4,886	4,869	4,864	4,859	4,854	4,857	4,871
DLCO	2,635	2,628	2,625	2,624	2,619	2,619	2,616	2,608	2,601	2,599	2,594	2,589	2,586	2,582	2,584	2,595
EKPC	1,919	1,927	1,936	1,944	1,956	1,966	1,972	1,976	1,980	1,988	1,994	2,004	2,012	2,024	2,033	2,047
OVEC	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
DOM	21,274	22,126	23,058	24,823	26,375	27,906	29,414	30,794	32,276	33,641	34,957	36,221	37,367	38,517	39,690	40,998
PJM RTO	149,058	149,739	150,924	152,734	154,275	155,703	156,923	157,899	158,941	159,920	160,971	162,095	163,140	164,542	165,975	167,569
PJM MID-ATLANTIC	54,240	53,996	53,962	53,878	53,673	53,535	53,393	53,168	52,981	52,789	52,718	52,675	52,726	52,787	52,971	53,063
EASTERN MID-ATLANTIC	29,385	29,195	29,128	29,035	28,875	28,785	28,679	28,521	28,387	28,262	28,216	28,181	28,198	28,217	28,333	28,362
SOUTHERN MID-ATLANTIC	12,127	12,085	12,093	12,082	12,050	12,012	11,978	11,915	11,866	11,800	11,768	11,756	11,757	11,772	11,789	11,808

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, 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 2023
SUMMER TOTAL INTERNAL DEMAND FORECAST (MW) FOR EACH NERC REGION
2023 - 2038

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Annual Growth Rate (10 yr)
PJM - RELIABILITY FIRST												
TOTAL INTERNAL DEMAND	125,866	125,684	125,930	125,969	125,944	125,831	125,537	125,129	124,686	124,288	124,020	(0.1%)
% GROWTH TOTAL		-0.1%	0.2%	0.0%	-0.0%	-0.1%	-0.2%	-0.3%	-0.4%	-0.3%	-0.2%	
CONTRACTUALLY INTERRUPTIBLE	6,410	6,490	6,513	6,518	6,524	6,519	6,499	6,485	6,470	6,446	6,431	
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	6,410	6,490	6,513	6,518	6,524	6,519	6,499	6,485	6,470	6,446	6,431	
NET INTERNAL DEMAND	119,456	119,194	119,417	119,451	119,420	119,312	119,038	118,644	118,216	117,842	117,589	(0.2%)
% GROWTH NET		-0.2%	0.2%	0.0%	-0.0%	-0.1%	-0.2%	-0.3%	-0.4%	-0.3%	-0.2%	
PJM - SERC												
TOTAL INTERNAL DEMAND	23,193	24,053	24,994	26,767	28,331	29,872	31,386	32,770	34,256	35,629	36,951	4.8%
% GROWTH TOTAL		3.7%	3.9%	7.1%	5.8%	5.4%	5.1%	4.4%	4.5%	4.0%	3.7%	
CONTRACTUALLY INTERRUPTIBLE	878	907	940	997	1,049	1,098	1,147	1,194	1,240	1,285	1,327	
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	878	907	940	997	1,049	1,098	1,147	1,194	1,240	1,285	1,327	
NET INTERNAL DEMAND	22,315	23,146	24,054	25,770	27,282	28,774	30,239	31,576	33,016	34,344	35,624	4.8%
% GROWTH NET		3.7%	3.9%	7.1%	5.9%	5.5%	5.1%	4.4%	4.6%	4.0%	3.7%	
PJM RTO												
TOTAL INTERNAL DEMAND	149,059	149,737	150,924	152,736	154,275	155,703	156,923	157,899	158,942	159,917	160,971	0.8%
% GROWTH TOTAL		0.5%	0.8%	1.2%	1.0%	0.9%	0.8%	0.6%	0.7%	0.6%	0.7%	
CONTRACTUALLY INTERRUPTIBLE	7,288	7,397	7,453	7,515	7,573	7,617	7,646	7,679	7,710	7,731	7,758	
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	7,288	7,397	7,453	7,515	7,573	7,617	7,646	7,679	7,710	7,731	7,758	
NET INTERNAL DEMAND	141,771	142,340	143,471	145,221	146,702	148,086	149,277	150,220	151,232	152,186	153,213	0.8%
% GROWTH NET		0.4%	0.8%	1.2%	1.0%	0.9%	0.8%	0.6%	0.7%	0.6%	0.7%	

Notes:
SERC includes EKPC and DOM zones and Reliability First includes all other zones.
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 (2023).

Table B-11 (Continued)

PJM CONTROL AREA - JANUARY 2023
SUMMER TOTAL INTERNAL DEMAND FORECAST (MW) FOR EACH NERC REGION
2023 - 2038

	2034	2035	2036	2037	2038	Annual Growth Rate (15 yr)
PJM - RELIABILITY FIRST						
TOTAL INTERNAL DEMAND	123,870	123,760	124,000	124,253	124,522	(0.1%)
% GROWTH TOTAL	-0.1%	-0.1%	0.2%	0.2%	0.2%	
CONTRACTUALLY INTERRUPTIBLE	6,420	6,410	6,425	6,437	6,449	
DIRECT CONTROL	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	6,420	6,410	6,425	6,437	6,449	
NET INTERNAL DEMAND	117,450	117,350	117,575	117,816	118,073	(0.1%)
% GROWTH NET	-0.1%	-0.1%	0.2%	0.2%	0.2%	
PJM - SERC						
TOTAL INTERNAL DEMAND	38,225	39,379	40,541	41,723	43,045	4.2%
% GROWTH TOTAL	3.4%	3.0%	3.0%	2.9%	3.2%	
CONTRACTUALLY INTERRUPTIBLE	1,366	1,403	1,441	1,480	1,520	
DIRECT CONTROL	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	1,366	1,403	1,441	1,480	1,520	
NET INTERNAL DEMAND	36,859	37,976	39,100	40,243	41,525	4.2%
% GROWTH NET	3.5%	3.0%	3.0%	2.9%	3.2%	
PJM RTO						
TOTAL INTERNAL DEMAND	162,095	163,139	164,541	165,976	167,567	0.8%
% GROWTH TOTAL	0.7%	0.6%	0.9%	0.9%	1.0%	
CONTRACTUALLY INTERRUPTIBLE	7,786	7,813	7,866	7,917	7,969	
DIRECT CONTROL	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	7,786	7,813	7,866	7,917	7,969	
NET INTERNAL DEMAND	154,309	155,326	156,675	158,059	159,598	0.8%
% GROWTH NET	0.7%	0.7%	0.9%	0.9%	1.0%	

Notes:
SERC includes EKPC and DOM zones and Reliability First includes all other zones.
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 (2023).

Table B-12

PJM CONTROL AREA - JANUARY 2023
WINTER TOTAL INTERNAL DEMAND FORECAST (MW) FOR EACH NERC REGION
2022/23 - 2032/33

	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32	32/33	Annual Growth Rate (10 yr)
PJM - RELIABILITY FIRST												
TOTAL INTERNAL DEMAND	125,083	125,731	126,345	128,126	129,824	132,252	132,893	134,272	135,544	137,335	137,947	1.0%
% GROWTH TOTAL		0.5%	0.5%	1.4%	1.3%	1.9%	0.5%	1.0%	0.9%	1.3%	0.4%	
CONTRACTUALLY INTERRUPTIBLE	4,494	4,488	4,506	4,511	4,517	4,514	4,502	4,492	4,481	4,468	4,457	
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	4,494	4,488	4,506	4,511	4,517	4,514	4,502	4,492	4,481	4,468	4,457	
NET INTERNAL DEMAND	120,589	121,243	121,839	123,615	125,307	127,738	128,391	129,780	131,063	132,867	133,490	1.0%
% GROWTH NET		0.5%	0.5%	1.5%	1.4%	1.9%	0.5%	1.1%	1.0%	1.4%	0.5%	
PJM - SERC												
TOTAL INTERNAL DEMAND	5,728	6,936	6,929	6,968	6,988	7,010	7,014	7,008	7,009	7,043	7,045	2.1%
% GROWTH TOTAL		21.1%	-0.1%	0.6%	0.3%	0.3%	0.1%	-0.1%	0.0%	0.5%	0.0%	
CONTRACTUALLY INTERRUPTIBLE	695	720	747	796	840	882	924	964	1,003	1,041	1,077	
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	695	720	747	796	840	882	924	964	1,003	1,041	1,077	
NET INTERNAL DEMAND	5,033	6,216	6,182	6,172	6,148	6,128	6,090	6,044	6,006	6,002	5,968	1.7%
% GROWTH NET		23.5%	-0.5%	-0.2%	-0.4%	-0.3%	-0.6%	-0.8%	-0.6%	-0.1%	-0.6%	
PJM RTO												
TOTAL INTERNAL DEMAND	130,811	132,667	133,274	135,094	136,812	139,262	139,907	141,280	142,553	144,378	144,992	1.0%
% GROWTH TOTAL		1.4%	0.5%	1.4%	1.3%	1.8%	0.5%	1.0%	0.9%	1.3%	0.4%	
CONTRACTUALLY INTERRUPTIBLE	5,189	5,208	5,253	5,307	5,357	5,396	5,426	5,456	5,484	5,509	5,534	
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	5,189	5,208	5,253	5,307	5,357	5,396	5,426	5,456	5,484	5,509	5,534	
NET INTERNAL DEMAND	125,622	127,459	128,021	129,787	131,455	133,866	134,481	135,824	137,069	138,869	139,458	1.1%
% GROWTH NET		1.5%	0.4%	1.4%	1.3%	1.8%	0.5%	1.0%	0.9%	1.3%	0.4%	

Notes:
SERC includes EKPC and DOM zones and Reliability First includes all other zones.
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 (2023).

Table B-12 (Continued)

PJM CONTROL AREA - JANUARY 2023
WINTER TOTAL INTERNAL DEMAND FORECAST (MW) FOR EACH NERC REGION
2022/23 - 2032/33

	33/34	34/35	35/36	36/37	37/38	Annual Growth Rate (15 yr)
PJM - RELIABILITY FIRST						
TOTAL INTERNAL DEMAND	138,920	140,068	141,716	142,273	143,423	0.9%
% GROWTH TOTAL	0.7%	0.8%	1.2%	0.4%	0.8%	
CONTRACTUALLY INTERRUPTIBLE	4,451	4,445	4,454	4,461	4,468	
DIRECT CONTROL	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	4,451	4,445	4,454	4,461	4,468	
NET INTERNAL DEMAND	134,469	135,623	137,262	137,812	138,955	0.9%
% GROWTH NET	0.7%	0.9%	1.2%	0.4%	0.8%	
PJM - SERC						
TOTAL INTERNAL DEMAND	7,058	7,068	7,080	7,106	7,132	1.5%
% GROWTH TOTAL	0.2%	0.1%	0.2%	0.4%	0.4%	
CONTRACTUALLY INTERRUPTIBLE	1,110	1,142	1,173	1,207	1,242	
DIRECT CONTROL	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	1,110	1,142	1,173	1,207	1,242	
NET INTERNAL DEMAND	5,948	5,926	5,907	5,899	5,890	1.1%
% GROWTH NET	-0.3%	-0.4%	-0.3%	-0.1%	-0.2%	
PJM RTO						
TOTAL INTERNAL DEMAND	145,978	147,136	148,796	149,379	150,555	0.9%
% GROWTH TOTAL	0.7%	0.8%	1.1%	0.4%	0.8%	
CONTRACTUALLY INTERRUPTIBLE	5,561	5,587	5,627	5,668	5,710	
DIRECT CONTROL	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	5,561	5,587	5,627	5,668	5,710	
NET INTERNAL DEMAND	140,417	141,549	143,169	143,711	144,845	1.0%
% GROWTH NET	0.7%	0.8%	1.1%	0.4%	0.8%	

Notes:
SERC includes EKPC and DOM zones and Reliability First includes all other zones.
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 (2023).

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
2023	18,699	22,824	19,096	21,205
2024	18,678	22,756	19,177	21,269
2025	18,704	22,793	19,277	21,252
2026	18,739	22,811	19,345	21,322
2027	18,755	22,795	19,301	21,406
2028	18,764	22,749	19,162	21,506
2029	18,779	22,682	19,135	21,441
2030	18,745	22,616	19,205	21,393
2031	18,689	22,557	19,232	21,390
2032	18,702	22,482	19,164	21,445
2033	18,753	22,484	19,096	21,391
2034	18,740	22,438	18,988	21,311
2035	18,752	22,392	19,039	21,304
2036	18,701	22,494	19,150	21,414
2037	18,767	22,544	19,213	21,376
2038	18,819	22,615	19,265	21,492

EXTREME WEATHER (90/10) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2023	20,504	24,306	21,134	22,732
2024	20,375	24,268	21,067	22,830
2025	20,373	24,388	21,145	22,742
2026	20,471	24,387	21,192	22,819
2027	20,508	24,209	21,176	22,869
2028	20,467	24,128	21,173	23,014
2029	20,446	24,276	20,972	22,877
2030	20,317	24,073	21,043	22,875
2031	20,258	24,223	21,114	22,877
2032	20,368	23,978	21,067	23,010
2033	20,351	23,991	21,056	22,921
2034	20,320	23,991	20,987	22,910
2035	20,293	24,035	20,855	22,901
2036	20,235	24,177	21,061	23,018
2037	20,319	24,230	21,119	22,971
2038	20,364	24,183	21,164	23,008

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, 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
2023	11,532	13,162	11,301	12,990
2024	11,499	13,159	11,326	12,995
2025	11,458	13,209	11,373	13,024
2026	11,516	13,259	11,433	13,037
2027	11,569	13,239	11,445	13,033
2028	11,566	13,214	11,373	13,097
2029	11,551	13,218	11,331	13,043
2030	11,521	13,175	11,362	13,032
2031	11,463	13,210	11,401	13,052
2032	11,540	13,235	11,449	13,086
2033	11,548	13,232	11,450	13,049
2034	11,533	13,187	11,393	13,014
2035	11,500	13,202	11,346	13,015
2036	11,440	13,249	11,414	13,026
2037	11,488	13,324	11,523	13,036
2038	11,551	13,323	11,558	13,044

EXTREME WEATHER (90/10) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2023	12,526	13,796	12,436	13,727
2024	12,497	13,785	12,437	13,720
2025	12,517	13,813	12,485	13,712
2026	12,527	13,839	12,488	13,726
2027	12,545	13,826	12,494	13,737
2028	12,525	13,843	12,481	13,763
2029	12,522	13,850	12,479	13,772
2030	12,503	13,846	12,494	13,759
2031	12,487	13,890	12,508	13,737
2032	12,491	13,859	12,528	13,743
2033	12,499	13,879	12,540	13,744
2034	12,467	13,894	12,535	13,741
2035	12,454	13,881	12,531	13,746
2036	12,445	13,968	12,619	13,749
2037	12,466	14,020	12,650	13,728
2038	12,493	13,999	12,677	13,748

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, 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
2023	22,004	30,783	24,735	21,821
2024	21,865	30,611	24,793	21,907
2025	21,694	30,563	24,844	21,890
2026	21,474	30,531	24,814	21,932
2027	21,340	30,398	24,697	21,965
2028	21,669	30,271	24,526	22,117
2029	21,599	30,160	24,422	22,000
2030	21,497	30,031	24,450	21,950
2031	21,194	29,970	24,421	21,931
2032	21,065	29,867	24,256	22,030
2033	21,225	29,749	24,132	21,937
2034	21,314	29,659	24,067	21,861
2035	21,291	29,646	24,046	21,804
2036	21,154	29,647	24,210	21,904
2037	21,141	29,809	24,248	21,849
2038	21,211	29,846	24,302	21,914

EXTREME WEATHER (90/10) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2023	25,170	33,099	27,846	22,992
2024	25,015	32,983	27,776	23,093
2025	24,716	32,952	27,832	23,070
2026	24,447	32,853	27,784	23,114
2027	24,085	32,701	27,691	23,151
2028	24,576	32,516	27,660	23,218
2029	24,631	32,323	27,479	23,162
2030	24,472	32,349	27,451	23,139
2031	24,164	32,307	27,436	23,101
2032	23,764	32,008	27,386	23,105
2033	24,180	31,854	27,323	23,025
2034	24,239	31,808	27,250	22,956
2035	24,317	31,805	27,207	22,929
2036	23,932	31,970	27,334	23,027
2037	23,972	32,030	27,444	22,982
2038	23,826	32,109	27,507	23,040

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, 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
2023	9,934	12,595	10,524	11,136
2024	9,881	12,549	10,546	11,132
2025	9,867	12,577	10,598	11,164
2026	9,883	12,551	10,609	11,193
2027	9,885	12,534	10,584	11,228
2028	9,891	12,492	10,517	11,261
2029	9,880	12,444	10,475	11,226
2030	9,860	12,382	10,482	11,215
2031	9,839	12,309	10,448	11,209
2032	9,825	12,281	10,404	11,228
2033	9,822	12,247	10,351	11,209
2034	9,829	12,189	10,343	11,205
2035	9,853	12,160	10,354	11,211
2036	9,857	12,191	10,424	11,248
2037	9,888	12,231	10,460	11,239
2038	9,895	12,270	10,485	11,260

EXTREME WEATHER (90/10) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2023	10,900	13,624	11,609	12,121
2024	10,859	13,555	11,580	12,041
2025	10,841	13,583	11,624	12,048
2026	10,846	13,553	11,636	12,079
2027	10,875	13,522	11,619	12,174
2028	10,909	13,431	11,593	12,215
2029	10,870	13,425	11,540	12,170
2030	10,794	13,347	11,496	12,139
2031	10,745	13,305	11,519	12,123
2032	10,764	13,226	11,484	12,111
2033	10,773	13,200	11,465	12,208
2034	10,781	13,165	11,365	12,200
2035	10,778	13,155	11,367	12,166
2036	10,753	13,208	11,503	12,158
2037	10,760	13,214	11,453	12,147
2038	10,815	13,237	11,499	12,221

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, 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 2023 - 2038

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
AE	2,706	2,678	2,665	2,655	2,647	2,635	2,623	2,604	2,590	2,585	2,568	2,556	2,548	2,544	2,545	2,548
BGE	7,109	7,042	7,022	6,988	6,938	6,882	6,813	6,751	6,725	6,669	6,625	6,601	6,575	6,563	6,552	6,546
DPL	4,072	4,046	4,025	4,006	3,990	3,969	3,963	3,945	3,934	3,924	3,913	3,895	3,894	3,900	3,910	3,916
JCPL	6,642	6,608	6,606	6,572	6,543	6,488	6,431	6,408	6,381	6,348	6,331	6,298	6,281	6,294	6,318	6,335
METED	3,201	3,207	3,217	3,225	3,230	3,238	3,245	3,251	3,255	3,259	3,265	3,270	3,277	3,291	3,304	3,320
PECO	9,124	9,123	9,157	9,172	9,150	9,151	9,156	9,157	9,189	9,149	9,144	9,154	9,163	9,212	9,224	9,225
PENLC	2,998	2,988	2,985	2,981	2,969	2,952	2,945	2,939	2,934	2,925	2,915	2,905	2,896	2,913	2,915	2,911
PEPCO	6,588	6,581	6,613	6,621	6,625	6,615	6,632	6,614	6,617	6,600	6,598	6,588	6,619	6,699	6,704	6,731
PL	7,545	7,539	7,570	7,581	7,576	7,579	7,583	7,578	7,590	7,577	7,577	7,579	7,598	7,627	7,647	7,673
PS	10,736	10,671	10,654	10,611	10,570	10,501	10,402	10,376	10,389	10,343	10,323	10,291	10,285	10,326	10,361	10,391
RECO	466	466	468	469	470	470	471	471	471	472	472	472	473	475	477	479
UGI	210	209	209	209	208	207	206	205	205	204	203	202	202	202	201	201
DIVERSITY - MID-ATLANTIC(-)	1,466	1,331	1,335	1,311	1,320	1,248	1,198	1,237	1,407	1,389	1,321	1,261	1,280	1,105	1,118	1,262
PJM MID-ATLANTIC	59,931	59,827	59,856	59,779	59,596	59,439	59,272	59,062	58,873	58,666	58,613	58,550	58,531	58,941	59,040	59,014
FE-EAST	12,508	12,455	12,471	12,451	12,409	12,359	12,330	12,307	12,322	12,299	12,252	12,215	12,200	12,314	12,344	12,341
PLGRP	7,751	7,744	7,776	7,786	7,783	7,781	7,784	7,780	7,792	7,778	7,775	7,776	7,798	7,826	7,846	7,872

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, 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
2023 - 2038

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
AEP	23,571	23,720	23,755	23,803	23,791	23,833	23,837	23,810	23,787	23,781	23,781	23,819	23,892	23,908	23,963	23,999
APS	9,288	9,352	9,690	9,881	10,067	10,132	10,119	10,111	10,095	10,083	10,078	10,064	10,061	10,091	10,102	10,115
ATSI	12,929	12,885	12,844	12,799	12,770	12,755	12,730	12,673	12,627	12,561	12,525	12,431	12,397	12,432	12,406	12,381
COMED	23,062	22,898	22,993	22,893	22,851	22,733	22,647	22,515	22,485	22,248	22,107	21,962	21,916	21,914	21,902	21,895
DAYTON	3,555	3,552	3,554	3,552	3,548	3,548	3,551	3,544	3,538	3,529	3,524	3,528	3,541	3,544	3,547	3,552
DEOK	5,620	5,612	5,610	5,603	5,594	5,587	5,571	5,550	5,526	5,509	5,501	5,490	5,483	5,479	5,479	5,479
DLCO	2,923	2,912	2,911	2,908	2,909	2,907	2,898	2,893	2,889	2,887	2,886	2,884	2,884	2,890	2,892	2,900
EKPC	2,152	2,159	2,166	2,171	2,180	2,188	2,194	2,196	2,195	2,197	2,204	2,211	2,219	2,225	2,233	2,236
OVEC	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
DIVERSITY - WESTERN(-)	615	597	837	910	938	916	873	880	1,046	1,017	1,032	892	970	969	944	924
PJM WESTERN	82,580	82,588	82,781	82,795	82,867	82,862	82,769	82,507	82,191	81,873	81,669	81,592	81,518	81,609	81,675	81,728
DOM	23,164	24,122	25,067	26,720	28,310	29,836	31,338	32,738	34,245	35,611	36,939	38,147	39,290	40,466	41,658	42,954
DIVERSITY - TOTAL(-)	5,090	5,275	4,713	4,505	5,763	5,708	5,667	5,797	5,641	6,270	6,390	6,422	5,955	5,908	5,326	6,687
PJM RTO	162,666	163,190	165,163	167,010	167,268	168,593	169,783	170,627	172,121	172,286	173,184	174,020	175,634	177,182	179,109	179,195

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, 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
2022/23 - 2037/38

	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32	32/33	33/34	34/35	35/36	36/37	37/38
AE	1,667	1,657	1,656	1,658	1,654	1,654	1,649	1,644	1,638	1,633	1,628	1,618	1,612	1,611	1,611	1,609
BGE	6,341	6,328	6,326	6,335	6,342	6,355	6,320	6,300	6,269	6,297	6,265	6,247	6,229	6,239	6,201	6,192
DPL	3,986	4,014	3,994	4,004	4,015	4,055	4,031	4,034	4,039	4,074	4,050	4,056	4,063	4,100	4,078	4,085
JCPL	3,904	3,945	3,949	3,978	3,994	4,033	4,022	4,027	4,019	4,036	4,039	4,028	4,014	4,031	4,039	4,055
METED	2,850	2,875	2,864	2,876	2,883	2,910	2,896	2,901	2,906	2,925	2,915	2,918	2,920	2,953	2,938	2,946
PECO	6,797	6,875	6,812	6,821	6,831	6,919	6,854	6,848	6,849	6,916	6,852	6,849	6,857	6,929	6,861	6,870
PENLC	2,976	2,978	2,956	2,955	2,947	2,950	2,931	2,922	2,910	2,909	2,894	2,882	2,874	2,871	2,860	2,854
PEPCO	5,842	5,826	5,841	5,889	5,916	5,932	5,940	5,931	5,942	5,976	5,994	6,011	6,023	6,042	6,065	6,087
PL	7,763	7,763	7,775	7,783	7,797	7,803	7,808	7,807	7,802	7,797	7,802	7,802	7,802	7,809	7,809	7,823
PS	6,807	6,812	6,799	6,781	6,773	6,772	6,755	6,719	6,686	6,671	6,638	6,606	6,591	6,602	6,580	6,590
RECO	223	228	233	239	244	249	252	255	256	257	258	258	258	260	263	266
UGI	209	208	208	208	207	207	206	205	204	203	203	202	200	200	199	199
DIVERSITY - MID-ATLANTIC(-)	1,500	1,354	1,439	1,454	1,379	1,337	1,359	1,345	1,298	1,483	1,404	1,456	1,418	1,513	1,484	1,442
PJM MID-ATLANTIC	47,865	48,155	47,974	48,073	48,224	48,502	48,305	48,248	48,222	48,211	48,134	48,021	48,025	48,134	48,020	48,134
FE-EAST	9,612	9,684	9,633	9,669	9,697	9,794	9,736	9,715	9,708	9,763	9,751	9,699	9,694	9,756	9,697	9,739
PLGRP	7,966	7,964	7,976	7,985	7,997	8,002	8,004	8,000	7,999	7,993	7,994	7,992	7,991	7,999	8,001	8,013

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, 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
2023 - 2038

	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32	32/33	33/34	34/35	35/36	36/37	37/38
AEP	24,140	24,564	24,401	24,429	24,452	24,779	24,504	24,473	24,433	24,668	24,423	24,489	24,449	24,676	24,454	24,482
APS	9,766	9,836	10,075	10,387	10,621	10,846	10,802	10,798	10,810	10,891	10,848	10,852	10,863	10,929	10,889	10,934
ATSI	10,317	10,352	10,305	10,267	10,247	10,286	10,250	10,212	10,153	10,119	10,034	9,987	9,947	9,919	9,848	9,801
COMED	15,195	15,225	15,233	15,295	15,364	15,443	15,532	15,505	15,514	15,465	15,432	15,384	15,352	15,297	15,243	15,240
DAYTON	3,077	3,089	3,088	3,075	3,082	3,085	3,069	3,060	3,047	3,045	3,025	3,012	3,017	3,018	3,003	3,006
DEOK	4,802	4,813	4,776	4,775	4,768	4,796	4,775	4,735	4,718	4,724	4,702	4,695	4,682	4,675	4,642	4,627
DLCO	2,083	2,094	2,076	2,070	2,070	2,084	2,068	2,058	2,053	2,060	2,043	2,038	2,035	2,046	2,026	2,028
EKPC	3,070	3,047	3,033	3,059	3,071	3,071	3,072	3,055	3,050	3,072	3,076	3,082	3,080	3,068	3,091	3,105
OVEC	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110
DIVERSITY - WESTERN(-)	2,303	1,989	2,261	2,399	2,454	2,175	2,394	2,404	2,452	2,267	2,354	2,369	2,289	2,108	2,356	2,387
PJM WESTERN	70,257	71,141	70,836	71,068	71,331	72,325	71,788	71,602	71,436	71,887	71,339	71,280	71,246	71,630	70,950	70,946
DOM	24,123	24,861	25,609	27,149	28,573	30,049	31,355	32,694	33,977	35,429	36,660	37,819	38,882	39,941	41,064	42,277
DIVERSITY - TOTAL(-)	5,352	6,057	5,401	5,650	5,540	5,912	5,736	5,472	5,412	6,066	5,383	5,347	5,406	5,800	5,276	5,414
PJM RTO	140,696	141,443	142,718	144,493	146,421	148,476	149,465	150,821	151,973	153,211	154,508	155,598	156,454	157,526	158,598	159,772

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, 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 2023 - 2033

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Annual Growth Rate (10 yr)
AE	9,644	9,621	9,545	9,494	9,433	9,403	9,311	9,239	9,165	9,125	9,020	(0.7%)
		-0.2%	-0.8%	-0.5%	-0.6%	-0.3%	-1.0%	-0.8%	-0.8%	-0.4%	-1.2%	
BGE	30,387	30,441	30,343	30,293	30,209	30,175	29,932	29,735	29,539	29,446	29,158	(0.4%)
		0.2%	-0.3%	-0.2%	-0.3%	-0.1%	-0.8%	-0.7%	-0.7%	-0.3%	-1.0%	
DPL	17,908	17,892	17,760	17,684	17,594	17,553	17,379	17,249	17,094	16,981	16,731	(0.7%)
		-0.1%	-0.7%	-0.4%	-0.5%	-0.2%	-1.0%	-0.7%	-0.9%	-0.7%	-1.5%	
JCPL	22,306	22,438	22,419	22,442	22,442	22,506	22,431	22,388	22,338	22,381	22,244	(0.0%)
		0.6%	-0.1%	0.1%	0.0%	0.3%	-0.3%	-0.2%	-0.2%	0.2%	-0.6%	
METED	15,938	16,075	16,063	16,118	16,163	16,273	16,254	16,285	16,321	16,441	16,390	0.3%
		0.9%	-0.1%	0.3%	0.3%	0.7%	-0.1%	0.2%	0.2%	0.7%	-0.3%	
PECO	38,739	38,970	38,889	38,944	38,970	39,150	39,043	39,057	39,077	39,283	39,119	0.1%
		0.6%	-0.2%	0.1%	0.1%	0.5%	-0.3%	0.0%	0.1%	0.5%	-0.4%	
PENLC	17,318	17,372	17,276	17,247	17,205	17,242	17,133	17,091	17,047	17,097	16,965	(0.2%)
		0.3%	-0.6%	-0.2%	-0.2%	0.2%	-0.6%	-0.2%	-0.3%	0.3%	-0.8%	
PEPCO	28,934	29,128	29,190	29,306	29,399	29,553	29,521	29,525	29,543	29,671	29,632	0.2%
		0.7%	0.2%	0.4%	0.3%	0.5%	-0.1%	0.0%	0.1%	0.4%	-0.1%	
PL	40,706	40,953	40,893	40,934	40,942	41,100	40,966	40,947	40,940	41,134	40,933	0.1%
		0.6%	-0.1%	0.1%	0.0%	0.4%	-0.3%	-0.0%	-0.0%	0.5%	-0.5%	
PS	41,632	41,621	41,330	41,074	40,787	40,594	40,178	39,807	39,444	39,248	38,750	(0.7%)
		-0.0%	-0.7%	-0.6%	-0.7%	-0.5%	-1.0%	-0.9%	-0.9%	-0.5%	-1.3%	
RECO	1,417	1,441	1,461	1,482	1,501	1,522	1,531	1,544	1,557	1,571	1,575	1.1%
		1.7%	1.4%	1.4%	1.3%	1.4%	0.6%	0.8%	0.8%	0.9%	0.3%	
UGI	1,038	1,041	1,035	1,031	1,028	1,028	1,022	1,019	1,014	1,015	1,006	(0.3%)
		0.3%	-0.6%	-0.4%	-0.3%	0.0%	-0.6%	-0.3%	-0.5%	0.1%	-0.9%	
PJM MID-ATLANTIC	265,967	266,993	266,204	266,049	265,673	266,099	264,701	263,886	263,079	263,393	261,523	(0.2%)
		0.4%	-0.3%	-0.1%	-0.1%	0.2%	-0.5%	-0.3%	-0.3%	0.1%	-0.7%	
FE-EAST	55,562	55,885	55,758	55,807	55,810	56,021	55,818	55,764	55,706	55,919	55,599	0.0%
		0.6%	-0.2%	0.1%	0.0%	0.4%	-0.4%	-0.1%	-0.1%	0.4%	-0.6%	
PLGRP	41,744	41,994	41,928	41,965	41,970	42,128	41,988	41,966	41,954	42,149	41,939	0.0%
		0.6%	-0.2%	0.1%	0.0%	0.4%	-0.3%	-0.1%	-0.0%	0.5%	-0.5%	

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation, reductions for distributed battery storage, and additions for plug-in electric vehicles.
All average growth rates are calculated from the first year of the forecast (2023).

Table E-1 (continued)

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION 2034 - 2038

	2034	2035	2036	2037	2038	Annual Growth Rate (15 yr)
AE	8,957	8,929	8,941	8,882	8,868	(0.6%)
	-0.7%	-0.3%	0.1%	-0.7%	-0.2%	
BGE	29,006	28,891	28,913	28,708	28,644	(0.4%)
	-0.5%	-0.4%	0.1%	-0.7%	-0.2%	
DPL	16,582	16,519	16,548	16,433	16,397	(0.6%)
	-0.9%	-0.4%	0.2%	-0.7%	-0.2%	
JCPL	22,216	22,254	22,402	22,374	22,450	0.0%
	-0.1%	0.2%	0.7%	-0.1%	0.3%	
METED	16,418	16,471	16,614	16,599	16,673	0.3%
	0.2%	0.3%	0.9%	-0.1%	0.4%	
PECO	39,133	39,201	39,464	39,376	39,483	0.1%
	0.0%	0.2%	0.7%	-0.2%	0.3%	
PENLC	16,916	16,891	16,962	16,866	16,857	(0.2%)
	-0.3%	-0.1%	0.4%	-0.6%	-0.1%	
PEPCO	29,720	29,881	30,118	30,112	30,246	0.3%
	0.3%	0.5%	0.8%	-0.0%	0.4%	
PL	40,922	40,946	41,221	41,139	41,250	0.1%
	-0.0%	0.1%	0.7%	-0.2%	0.3%	
PS	38,454	38,269	38,294	38,048	37,999	(0.6%)
	-0.8%	-0.5%	0.1%	-0.6%	-0.1%	
RECO	1,586	1,599	1,621	1,627	1,646	1.0%
	0.7%	0.8%	1.4%	0.4%	1.2%	
UGI	1,002	998	1,002	996	997	(0.3%)
	-0.4%	-0.4%	0.4%	-0.6%	0.1%	
PJM MID-ATLANTIC	260,912	260,849	262,100	261,160	261,510	(0.1%)
	-0.2%	-0.0%	0.5%	-0.4%	0.1%	
FE-EAST	55,550	55,616	55,978	55,839	55,980	0.0%
	-0.1%	0.1%	0.7%	-0.2%	0.3%	
PLGRP	41,924	41,944	42,223	42,135	42,247	0.1%
	-0.0%	0.0%	0.7%	-0.2%	0.3%	

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation, reductions for distributed battery storage, and additions for plug-in electric vehicles.
All average growth rates are calculated from the first year of the forecast (2023).

Table E-1

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO 2023 - 2033

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Annual Growth Rate (10 yr)
AEP	130,238	132,670	132,525	132,776	133,006	133,725	133,367	133,303	133,315	134,008	133,489	0.2%
		1.9%	-0.1%	0.2%	0.2%	0.5%	-0.3%	-0.0%	0.0%	0.5%	-0.4%	
APS	49,918	50,988	53,639	55,508	57,285	58,265	58,087	58,074	58,078	58,354	58,095	1.5%
		2.1%	5.2%	3.5%	3.2%	1.7%	-0.3%	-0.0%	0.0%	0.5%	-0.4%	
ATSI	62,545	62,782	62,349	62,167	62,164	62,476	62,241	61,964	61,641	61,616	61,073	(0.2%)
		0.4%	-0.7%	-0.3%	-0.0%	0.5%	-0.4%	-0.4%	-0.5%	-0.0%	-0.9%	
COMED	90,558	90,989	90,708	90,720	90,896	91,373	91,230	91,157	90,844	90,771	90,106	(0.1%)
		0.5%	-0.3%	0.0%	0.2%	0.5%	-0.2%	-0.1%	-0.3%	-0.1%	-0.7%	
DAYTON	16,944	17,016	16,964	16,960	16,947	16,994	16,911	16,858	16,823	16,876	16,775	(0.1%)
		0.4%	-0.3%	-0.0%	-0.1%	0.3%	-0.5%	-0.3%	-0.2%	0.3%	-0.6%	
DEOK	26,599	26,669	26,561	26,514	26,465	26,493	26,333	26,196	26,073	26,070	25,870	(0.3%)
		0.3%	-0.4%	-0.2%	-0.2%	0.1%	-0.6%	-0.5%	-0.5%	-0.0%	-0.8%	
DLCO	13,210	13,250	13,197	13,179	13,158	13,188	13,123	13,091	13,059	13,094	13,009	(0.2%)
		0.3%	-0.4%	-0.1%	-0.2%	0.2%	-0.5%	-0.2%	-0.2%	0.3%	-0.6%	
EKPC	11,246	11,395	11,446	11,512	11,593	11,721	11,739	11,783	11,831	11,940	11,944	0.6%
		1.3%	0.4%	0.6%	0.7%	1.1%	0.2%	0.4%	0.4%	0.9%	0.0%	
OVEC	330	330	330	330	330	330	330	330	330	330	330	0.0%
		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
PJM WESTERN	401,588	406,089	407,719	409,666	411,844	414,565	413,361	412,756	411,994	413,059	410,691	0.2%
		1.1%	0.4%	0.5%	0.5%	0.7%	-0.3%	-0.1%	-0.2%	0.3%	-0.6%	
DOM	120,495	128,855	136,328	150,796	163,997	177,605	189,774	201,819	214,320	226,951	237,408	7.0%
		6.9%	5.8%	10.6%	8.8%	8.3%	6.9%	6.3%	6.2%	5.9%	4.6%	
PJM RTO	788,050	801,937	810,251	826,511	841,514	858,269	867,836	878,461	889,393	903,403	909,622	1.4%
		1.8%	1.0%	2.0%	1.8%	2.0%	1.1%	1.2%	1.2%	1.6%	0.7%	

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation, reductions for distributed battery storage, and additions for plug-in electric vehicles.
All average growth rates are calculated from the first year of the forecast (2023).

Table E-1 (Continued)

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO 2023 - 2033

	2034	2035	2036	2037	2038	Annual Growth Rate (15 yr)
AEP	133,648	133,896	134,806	134,515	134,856	0.2%
	0.1%	0.2%	0.7%	-0.2%	0.3%	
APS	58,110	58,176	58,533	58,365	58,473	1.1%
	0.0%	0.1%	0.6%	-0.3%	0.2%	
ATSI	60,833	60,623	60,706	60,230	60,061	(0.3%)
	-0.4%	-0.3%	0.1%	-0.8%	-0.3%	
COMED	89,960	90,006	90,484	90,163	90,253	(0.0%)
	-0.2%	0.1%	0.5%	-0.4%	0.1%	
DAYTON	16,761	16,770	16,859	16,796	16,815	(0.1%)
	-0.1%	0.1%	0.5%	-0.4%	0.1%	
DEOK	25,793	25,751	25,810	25,664	25,632	(0.2%)
	-0.3%	-0.2%	0.2%	-0.6%	-0.1%	
DLCO	12,985	12,981	13,045	13,001	13,017	(0.1%)
	-0.2%	-0.0%	0.5%	-0.3%	0.1%	
EKPC	12,006	12,069	12,201	12,217	12,293	0.6%
	0.5%	0.5%	1.1%	0.1%	0.6%	
OVEC	330	330	330	330	330	0.0%
	0.0%	0.0%	0.0%	0.0%	0.0%	
PJM WESTERN	410,426	410,602	412,774	411,281	411,730	0.2%
	-0.1%	0.0%	0.5%	-0.4%	0.1%	
DOM	247,810	257,503	267,876	276,725	287,188	6.0%
	4.4%	3.9%	4.0%	3.3%	3.8%	
PJM RTO	919,148	928,954	942,750	949,166	960,428	1.3%
	1.0%	1.1%	1.5%	0.7%	1.2%	

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation, reductions for distributed battery storage, and additions for plug-in electric vehicles.
All average growth rates are calculated from the first year of the forecast (2023).

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 2023	835	2,952	1,784	1,971	1,505	3,547	1,650	2,749	4,050	3,637	117	108	24,905
Feb 2023	723	2,550	1,548	1,694	1,322	3,103	1,462	2,379	3,524	3,170	101	94	21,670
Mar 2023	714	2,482	1,489	1,718	1,348	3,133	1,519	2,317	3,539	3,277	105	93	21,734
Apr 2023	623	2,067	1,198	1,499	1,149	2,703	1,312	1,966	2,959	2,859	95	74	18,504
May 2023	703	2,218	1,263	1,647	1,195	2,893	1,328	2,158	3,010	3,123	112	73	19,723
Jun 2023	865	2,606	1,494	2,007	1,325	3,370	1,388	2,521	3,243	3,724	134	80	22,757
Jul 2023	1,125	3,053	1,816	2,449	1,493	3,967	1,523	2,960	3,685	4,421	159	93	26,744
Aug 2023	1,066	2,925	1,730	2,341	1,488	3,844	1,497	2,835	3,590	4,298	152	88	25,854
Sep 2023	808	2,376	1,378	1,808	1,234	3,126	1,318	2,310	3,059	3,433	119	74	21,043
Oct 2023	682	2,153	1,236	1,605	1,198	2,798	1,360	2,073	3,037	3,077	104	76	19,399
Nov 2023	693	2,278	1,334	1,646	1,242	2,887	1,401	2,151	3,259	3,093	103	84	20,171
Dec 2023	807	2,727	1,638	1,921	1,439	3,368	1,560	2,515	3,751	3,520	116	101	23,463

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	MID-ATLANTIC
Jan 2024	832	2,953	1,785	1,982	1,518	3,563	1,653	2,762	4,068	3,642	119	108	24,985
Feb 2024	755	2,662	1,616	1,786	1,407	3,282	1,543	2,488	3,710	3,312	108	98	22,767
Mar 2024	707	2,464	1,479	1,709	1,335	3,115	1,499	2,308	3,508	3,233	106	92	21,555
Apr 2024	622	2,073	1,197	1,515	1,169	2,728	1,326	1,985	2,994	2,871	97	75	18,652
May 2024	699	2,209	1,253	1,649	1,199	2,893	1,324	2,159	3,012	3,103	113	73	19,686
Jun 2024	854	2,584	1,474	1,994	1,318	3,354	1,373	2,510	3,223	3,677	134	79	22,574
Jul 2024	1,116	3,048	1,807	2,453	1,509	3,986	1,533	2,976	3,715	4,418	161	93	26,815
Aug 2024	1,057	2,910	1,715	2,336	1,486	3,839	1,487	2,836	3,583	4,269	153	88	25,759
Sep 2024	803	2,372	1,368	1,810	1,239	3,132	1,317	2,320	3,065	3,417	120	74	21,037
Oct 2024	681	2,158	1,233	1,620	1,211	2,814	1,366	2,091	3,061	3,082	106	76	19,499
Nov 2024	689	2,274	1,326	1,650	1,240	2,883	1,392	2,157	3,252	3,076	105	84	20,128
Dec 2024	806	2,734	1,639	1,934	1,444	3,381	1,559	2,536	3,762	3,521	119	101	23,536

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	MID-ATLANTIC
Jan 2025	831	2,960	1,786	1,996	1,524	3,571	1,650	2,779	4,079	3,641	122	108	25,047
Feb 2025	718	2,551	1,544	1,707	1,331	3,113	1,455	2,398	3,535	3,155	105	94	21,706
Mar 2025	705	2,468	1,474	1,717	1,344	3,126	1,501	2,323	3,525	3,226	108	92	21,609
Apr 2025	618	2,071	1,190	1,519	1,171	2,731	1,322	1,994	2,997	2,854	99	75	18,641
May 2025	693	2,203	1,242	1,647	1,198	2,891	1,317	2,163	3,009	3,071	114	73	19,621
Jun 2025	848	2,584	1,466	1,996	1,328	3,369	1,377	2,525	3,242	3,666	136	79	22,616
Jul 2025	1,109	3,046	1,798	2,454	1,520	4,001	1,536	2,993	3,736	4,405	163	93	26,854
Aug 2025	1,050	2,902	1,703	2,329	1,484	3,836	1,478	2,843	3,576	4,235	154	87	25,677
Sep 2025	800	2,377	1,364	1,819	1,251	3,150	1,324	2,340	3,089	3,416	123	74	21,127
Oct 2025	679	2,160	1,228	1,627	1,215	2,819	1,364	2,103	3,067	3,070	108	76	19,516
Nov 2025	687	2,273	1,321	1,654	1,239	2,881	1,386	2,166	3,249	3,057	107	83	20,103
Dec 2025	807	2,748	1,644	1,954	1,458	3,401	1,566	2,563	3,789	3,534	122	101	23,687

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation, reductions for distributed battery storage, and additions for plug-in electric vehicles.

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	OVEC	PJM WESTERN	DOM	PJM RTO
Jan 2023	12,539	4,978	5,794	8,147	1,606	2,459	1,168	1,229	35	37,955	11,115	73,975
Feb 2023	10,814	4,318	5,116	7,152	1,391	2,112	1,030	1,013	30	32,976	9,555	64,201
Mar 2023	11,019	4,324	5,323	7,296	1,410	2,141	1,059	957	25	33,554	9,470	64,758
Apr 2023	9,520	3,627	4,611	6,463	1,210	1,877	948	764	25	29,045	8,383	55,932
May 2023	9,971	3,736	4,790	6,880	1,286	2,065	1,029	798	25	30,580	9,125	59,428
Jun 2023	10,793	4,011	5,299	8,076	1,439	2,346	1,177	891	25	34,057	10,208	67,022
Jul 2023	11,748	4,415	5,825	9,062	1,567	2,590	1,321	986	35	37,549	11,650	75,943
Aug 2023	11,710	4,404	5,754	8,877	1,583	2,584	1,297	973	30	37,212	11,400	74,466
Sep 2023	10,114	3,740	4,839	7,293	1,324	2,141	1,066	809	25	31,351	9,783	62,177
Oct 2023	9,926	3,724	4,767	6,760	1,287	1,970	992	792	20	30,238	9,184	58,821
Nov 2023	10,345	3,983	4,891	6,844	1,338	2,000	1,001	911	25	31,338	9,529	61,038
Dec 2023	11,739	4,658	5,536	7,708	1,503	2,314	1,122	1,123	30	35,733	11,093	70,289

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	OVEC	WESTERN	DOM	PJM RTO
Jan 2024	12,760	5,009	5,826	8,190	1,614	2,462	1,171	1,234	35	38,301	11,770	75,056
Feb 2024	11,554	4,577	5,402	7,534	1,468	2,217	1,083	1,071	30	34,936	10,611	68,314
Mar 2024	11,085	4,304	5,258	7,219	1,391	2,119	1,049	960	25	33,410	10,081	65,046
Apr 2024	9,756	3,680	4,660	6,533	1,226	1,890	954	778	25	29,502	9,063	57,217
May 2024	10,116	3,766	4,781	6,875	1,283	2,059	1,027	806	25	30,738	9,796	60,220
Jun 2024	10,871	4,030	5,250	7,995	1,424	2,327	1,169	896	25	33,987	10,834	67,395
Jul 2024	11,961	4,501	5,855	9,100	1,578	2,597	1,325	997	35	37,949	12,329	77,093
Aug 2024	11,826	4,472	5,725	8,847	1,574	2,573	1,292	980	30	37,319	12,043	75,121
Sep 2024	10,265	3,840	4,835	7,290	1,324	2,139	1,065	819	25	31,602	10,439	63,078
Oct 2024	10,126	3,866	4,791	6,821	1,297	1,978	996	805	20	30,700	9,882	60,081
Nov 2024	10,460	4,112	4,869	6,844	1,332	1,993	997	918	25	31,550	10,180	61,858
Dec 2024	11,890	4,831	5,530	7,741	1,505	2,315	1,122	1,131	30	36,095	11,827	71,458

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	OVEC	WESTERN	DOM	PJM RTO
Jan 2025	12,803	5,220	5,816	8,218	1,615	2,464	1,171	1,242	35	38,584	12,332	75,963
Feb 2025	10,994	4,550	5,104	7,166	1,392	2,109	1,029	1,025	30	33,399	10,653	65,758
Mar 2025	11,144	4,580	5,264	7,244	1,396	2,124	1,051	970	25	33,798	10,671	66,078
Apr 2025	9,776	3,935	4,639	6,532	1,225	1,887	953	786	25	29,758	9,654	58,053
May 2025	10,120	4,026	4,751	6,851	1,278	2,052	1,023	814	25	30,940	10,428	60,989
Jun 2025	10,934	4,292	5,252	8,013	1,432	2,331	1,171	906	25	34,356	11,489	68,461
Jul 2025	12,019	4,763	5,852	9,112	1,585	2,601	1,327	1,007	35	38,301	13,033	78,188
Aug 2025	11,812	4,701	5,677	8,798	1,567	2,563	1,288	987	30	37,423	12,734	75,834
Sep 2025	10,345	4,088	4,846	7,329	1,334	2,146	1,069	830	25	32,012	11,172	64,311
Oct 2025	10,151	4,098	4,772	6,824	1,297	1,975	995	812	20	30,944	10,619	61,079
Nov 2025	10,456	4,319	4,833	6,822	1,327	1,985	994	925	25	31,686	10,894	62,683
Dec 2025	11,971	5,067	5,543	7,799	1,516	2,324	1,126	1,142	30	36,518	12,649	72,854

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation, reductions for distributed battery storage, and additions for plug-in electric vehicles.

Table E-3

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

	FE_EAST	PLGRP
Jan 2023	5,126	4,158
Feb 2023	4,478	3,618
Mar 2023	4,585	3,632
Apr 2023	3,960	3,033
May 2023	4,170	3,083
Jun 2023	4,720	3,323
Jul 2023	5,465	3,778
Aug 2023	5,326	3,678
Sep 2023	4,360	3,133
Oct 2023	4,163	3,113
Nov 2023	4,289	3,343
Dec 2023	4,920	3,852

	FE_EAST	PLGRP
Jan 2024	5,153	4,176
Feb 2024	4,736	3,808
Mar 2024	4,543	3,600
Apr 2024	4,010	3,069
May 2024	4,172	3,085
Jun 2024	4,685	3,302
Jul 2024	5,495	3,808
Aug 2024	5,309	3,671
Sep 2024	4,366	3,139
Oct 2024	4,197	3,137
Nov 2024	4,282	3,336
Dec 2024	4,937	3,863

	FE_EAST	PLGRP
Jan 2025	5,170	4,187
Feb 2025	4,493	3,629
Mar 2025	4,562	3,617
Apr 2025	4,012	3,072
May 2025	4,162	3,082
Jun 2025	4,701	3,321
Jul 2025	5,510	3,829
Aug 2025	5,291	3,663
Sep 2025	4,394	3,163
Oct 2025	4,206	3,143
Nov 2025	4,279	3,332
Dec 2025	4,978	3,890

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation, reductions for distributed battery storage, and additions for plug-in electric vehicles.

Table E-4

PLUG IN ELECTRIC VEHICLE ADJUSTMENT TO ANNUAL ENERGY (GWh) FOR EACH PJM ZONE AND RTO
2023 - 2038

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
AE	22	49	82	116	148	177	204	229	252	274	293	311	328	345	358	372
BGE	48	111	190	274	351	425	491	554	613	670	719	767	811	856	893	930
DPL	10	22	36	50	64	77	90	103	116	129	141	154	166	179	191	203
JCPL	87	191	319	454	580	699	807	909	1,005	1,098	1,179	1,257	1,331	1,405	1,467	1,529
METED	5	11	17	22	28	34	39	45	50	56	62	67	73	79	84	90
PECO	19	40	61	82	103	123	143	164	184	206	227	248	269	291	311	332
PENLC	6	13	20	27	33	40	46	52	59	65	71	77	83	89	94	100
PEPCO	68	157	268	389	508	627	743	863	984	1,112	1,237	1,367	1,509	1,615	1,672	1,736
PL	7	14	22	30	37	45	52	59	66	74	81	89	96	104	111	119
PS	72	158	264	375	479	578	667	752	831	908	975	1,040	1,101	1,162	1,213	1,264
RECO	18	39	65	93	119	143	166	187	207	226	243	259	275	291	304	317
UGI	0	1	1	2	2	2	3	3	3	4	4	4	5	5	5	6
AEP	33	72	115	159	202	243	281	320	357	396	431	467	502	538	570	604
APS	20	44	72	102	129	156	181	205	228	252	273	294	314	334	352	370
ATSI	23	49	73	98	122	146	169	191	214	238	260	283	305	328	349	370
COMED	118	275	472	715	1,007	1,360	1,757	2,263	2,583	2,706	2,839	2,967	3,092	3,223	3,330	3,442
DAYTON	4	9	14	19	24	28	33	37	41	46	50	55	59	64	68	72
DEOK	7	14	21	28	35	42	49	56	63	70	77	84	91	99	105	112
DLCO	5	11	16	22	27	33	38	43	48	54	59	64	69	74	79	84
EKPC	2	5	8	10	13	16	18	21	23	26	28	31	34	37	39	42
OVEC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DOM	143	342	594	867	1,126	1,379	1,615	1,851	2,062	2,254	2,425	2,592	2,750	2,910	3,046	3,184
PJM RTO	718	1,629	2,731	3,932	5,137	6,375	7,592	8,906	9,992	10,863	11,673	12,477	13,263	14,027	14,642	15,278

Notes:
Adjustment values presented here are reflected in all energy forecast values.

Table F-1

PJM RTO HISTORICAL PEAKS
(MW)

SUMMER

YEAR	NORMALIZED TOTAL	UNRESTRICTED PEAK	PEAK DATE	TIME
1997		130,126	Thursday, July 17, 1997	17:00
1998		133,275	Tuesday, July 21, 1998	17:00
1999		141,491	Friday, July 30, 1999	17:00
2000		131,798	Wednesday, August 9, 2000	17:00
2001		150,924	Thursday, August 9, 2001	16:00
2002		150,826	Thursday, August 1, 2002	17:00
2003		145,227	Thursday, August 21, 2003	17:00
2004		139,279	Tuesday, August 3, 2004	17:00
2005		155,257	Tuesday, July 26, 2005	16:00
2006		166,929	Wednesday, August 2, 2006	17:00
2007		162,035	Wednesday, August 8, 2007	16:00
2008		150,622	Monday, June 9, 2008	17:00
2009		145,112	Monday, August 10, 2009	16:00
2010		157,247	Wednesday, July 7, 2010	17:00
2011		165,524	Thursday, July 21, 2011	17:00
2012		158,219	Tuesday, July 17, 2012	17:00
2013	151,660	159,149	Thursday, July 18, 2013	17:00
2014	151,834	141,509	Tuesday, June 17, 2014	18:00
2015	150,837	143,579	Tuesday, July 28, 2015	17:00
2016	150,408	152,069	Thursday, August 11, 2016	16:00
2017	150,656	145,434	Wednesday, July 19, 2017	18:00
2018	150,493	150,573	Tuesday, August 28, 2018	17:00
2019	150,155	151,302	Friday, July 19, 2019	18:00
2020	147,328	144,320	Monday, July 20, 2020	17:00
2021	149,960	148,433	Tuesday, August 24, 2021	18:00
2022	149,350	147,361	Wednesday, July 20, 2022	18:00

Notes:
Normalized values for 2013 - 2022 are calculated by PJM staff using a methodology described in Manual 19.
All times are shown in hour ending Eastern Prevailing Time and historic peak values reflect current membership of the PJM RTO.

Table F-1

PJM RTO HISTORICAL PEAKS
(MW)

WINTER

YEAR	NORMALIZED TOTAL	UNRESTRICTED PEAK	PEAK DATE	TIME
96/97		114,015	Friday, January 17, 1997	19:00
97/98		103,231	Wednesday, January 14, 1998	19:00
98/99		116,086	Tuesday, January 5, 1999	19:00
99/00		118,435	Thursday, January 27, 2000	20:00
00/01		118,046	Wednesday, December 20, 2000	19:00
01/02		112,217	Wednesday, January 2, 2002	19:00
02/03		129,965	Thursday, January 23, 2003	19:00
03/04		122,424	Friday, January 23, 2004	9:00
04/05		131,234	Monday, December 20, 2004	19:00
05/06		126,777	Wednesday, December 14, 2005	19:00
06/07		136,804	Monday, February 5, 2007	20:00
07/08		128,368	Wednesday, January 2, 2008	19:00
08/09		134,077	Friday, January 16, 2009	19:00
09/10		125,350	Monday, January 4, 2010	19:00
10/11		132,315	Tuesday, December 14, 2010	19:00
11/12		124,506	Tuesday, January 3, 2012	19:00
12/13		128,810	Tuesday, January 22, 2013	19:00
13/14	129,932	141,866	Tuesday, January 7, 2014	19:00
14/15	130,728	142,856	Friday, February 20, 2015	8:00
15/16	130,951	129,540	Tuesday, January 19, 2016	8:00
16/17	130,237	130,825	Thursday, December 15, 2016	19:00
17/18	130,766	137,212	Friday, January 5, 2018	19:00
18/19	130,647	137,618	Thursday, January 31, 2019	8:00
19/20	131,455	120,272	Thursday, December 19, 2019	8:00
20/21	129,550	117,012	Friday, January 29, 2021	9:00
21/22	130,888	128,882	Thursday, January 27, 2022	8:00

Notes:
Normalized values for 2013/14 - 2021/22 are calculated by PJM staff using a methodology described in Manual 19.
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	718,248	2.4%
1999	740,056	3.0%
2000	756,211	2.2%
2001	754,516	-0.2%
2002	782,275	3.7%
2003	780,666	-0.2%
2004	796,702	2.1%
2005	823,342	3.3%
2006	802,984	-2.5%
2007	836,241	4.1%
2008	822,608	-1.6%
2009	781,270	-5.0%
2010	820,038	5.0%
2011	805,911	-1.7%
2012	791,768	-1.8%
2013	795,098	0.4%
2014	796,228	0.1%
2015	791,580	-0.6%
2016	791,176	-0.1%
2017	772,291	-2.4%
2018	804,917	4.2%
2019	785,209	-2.4%
2020	755,241	-3.8%
2021	780,454	3.3%

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

Table F-3

WEATHER NORMALIZED LOAD (MW) FOR EACH PJM ZONE, LOCATIONAL DELIVERABILITY AREA AND RTO

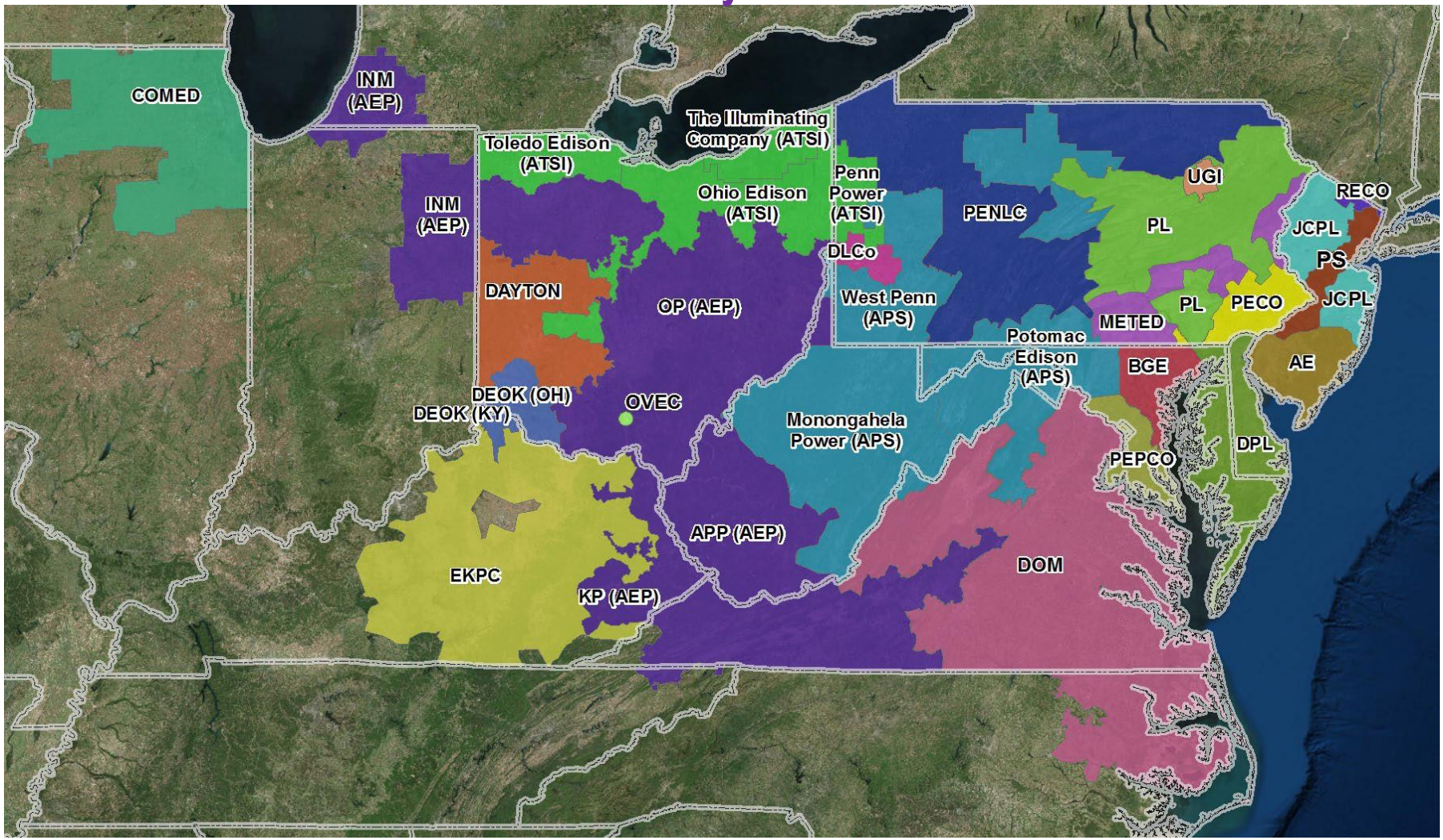
	Summer 2022	Winter 2021/22
AE	2,632	1,658
BGE	6,591	5,804
DPL	4,017	3,743
JCPL	6,058	3,745
METED	3,045	2,697
PECO	8,629	6,550
PENLC	2,893	2,844
PEPCO	6,100	5,293
PL	7,241	7,390
PS	9,943	6,560
RECO	411	212
UGI	202	204
AEP	22,189	22,077
APS	8,753	8,990
ATSI	12,423	10,290
COMED	20,781	14,808
DAYTON	3,355	2,974
DEOK	5,239	4,457
DLCO	2,720	2,004
EKPC	2,040	2,687
OVEC	95	110
DOM	21,160	21,000
PJM MID-ATLANTIC	56,266	45,937
PJM WESTERN	75,980	66,664
PJM RTO	149,350	130,888

Notes:
Zonal Normal 2022 are non-coincident as estimated by PJM staff.
Locational Deliverability Area and PJM RTO Normal 2022 are coincident with their regional peak as estimated by PJM staff.

EXHIBIT NO. 49

PJM Load Forecast Report

January 2024



Prepared by PJM Resource Adequacy Planning Department

Revised 2/1/2024

TABLE OF CONTENTS

	TABLE NUMBER	CHART PAGE	TABLE PAGE
EXECUTIVE SUMMARY			1
FORECAST COMPARISON:			
Each Zone and PJM RTO – Comparison to Prior Summer Peak Forecasts	A-1		29
Each Zone and PJM RTO – Comparison to Prior Winter Peak Forecasts	A-2		31
PEAK LOAD FORECAST AND ANNUAL GROWTH RATES:			
Summer Peak Forecasts and Growth Rates of each Zone, Geographic Region and PJM RTO	B-1	3-28	33
Winter Peak Forecasts and Growth Rates of each Zone, Geographic Region and PJM RTO	B-2	3-28	37
Spring Peak Forecasts of each Zone, Geographic Region and PJM RTO	B-3		41
Fall Peak Forecasts of each Zone, Geographic Region and PJM RTO	B-4		43
Monthly Peak Forecasts of each Zone, Geographic Region and PJM RTO	B-5		45
Monthly Peak Forecasts of FE-East and PLGrp	B-6		47
Load Management Placed Under PJM Coordination by Zone, used in Planning	B-7		48
Distributed Solar Adjustments to Summer Peak Forecasts	B-8a		54
Distributed Battery Storage Adjustments to Summer Peak Forecasts	B-8b		55
Plug-In Electric Vehicle Adjustments to Summer Peak Forecasts	B-8c		56
Adjustments Above Embedded to Summer Peak Forecasts	B-9		57
Summer Coincident Peak Load Forecasts of each Zone, Locational Deliverability Area and PJM RTO (RPM Forecast)	B-10		58

	TABLE NUMBER	CHART PAGE	TABLE PAGE
Seasonal Unrestricted PJM Control Area Peak Forecasts of each NERC Region	B-11,B-12		59
LOCATIONAL DELIVERABILITY AREA SEASONAL PEAKS:			
Central Mid-Atlantic: BGE, MetEd, PEPCO, PL and UGI Seasonal Peaks	C-1		63
Western Mid-Atlantic: MetEd, PENLC, PL and UGI Seasonal Peaks	C-2		64
Eastern Mid-Atlantic: AE, DPL, JCPL, PECO, PS and RECO Seasonal Peaks	C-3		65
Southern Mid-Atlantic: BGE and PEPCO Seasonal Peaks	C-4		66
EXTREME WEATHER (90/10) PEAK LOAD FORECASTS:			
Summer 90/10 Peak Forecasts of each Zone, Geographic Region and PJM RTO	D-1		67
Winter 90/10 Peak Forecasts of each Zone, Geographic Region and PJM RTO	D-2		69
NET ENERGY FORECAST AND ANNUAL GROWTH RATES:			
Annual Net Energy Forecasts of each Zone, Geographic Region and PJM RTO	E-1		71
Monthly Net Energy Forecasts of each Zone, Geographic Region and PJM RTO	E-2		75
Monthly Net Energy Forecasts of FE-East and PLGrp	E-3		77
Annual Plug-In Vehicle Net Energy Forecasts of each Zone, Geographic Region and PJM RTO	E-4		78

	TABLE NUMBER	CHART PAGE	TABLE PAGE
PJM HISTORICAL DATA:			
Historical RTO Summer and Winter Peaks	F-1		79
Historical RTO Net Energy for Load	F-2		81
Weather-Normalized Seasonal Peaks of each Zone, Geographic Region and PJM RTO	F-3		82

TERMS AND ABBREVIATIONS USED IN THIS REPORT

AE	Atlantic Electric zone
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)
Battery Storage	(Also Battery Energy Storage System – BESS) Devices that enable generated energy to be stored and then released at a later time
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
EKPC	East Kentucky Power Cooperative zone (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
OVEC	Ohio Valley Electric Corporation zone (incorporated 12/1/2018)
PECO	PECO Energy zone
PED	Potomac Edison, sub-zone of APS
PEPCO	Potomac Electric Power zone
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
PRD	Price Responsive Demand
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 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

2024 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, distributed solar generation, plug-in electric vehicles, and battery storage for each PJM zone, region, locational deliverability area (LDA), and the total RTO.

- Residential, Commercial, and Industrial sector models were estimated with data from 2013 through 2022. Weather scenarios were simulated with data from years 1994 through 2022, generating 377 scenarios.

- The economic forecast used was Moody's Analytics' September 2023 release.

- The 2023 update of Itron's end-use data provides the basis for appliance saturation rates, efficiency, and intensity and is consistent with the Energy Information Administration's 2023 Annual Energy Outlook. PJM obtained additional information from certain zones on Residential saturation rates based on their own load research. Details on zones providing information are presented in the supplement.

- Consultant forecasts for behind the meter solar/battery and electric vehicles including light, medium & heavy duty were provided by S&P Global.

    - The behind the meter solar/battery values were derived by PJM from a forecast obtained from SPGCI
    - The electric vehicle values were derived by PJM from a forecast obtained from SPGCI

- The forecasts of the following zones have been adjusted to account for large, unanticipated load changes, market adjustments, and peak shaving adjustments (see Table B-9 and the supplement for details):
    - The AEP zone has been adjusted to account for growth in data center load and a chip processing plant;
    - The APS zone has been adjusted to account for growth in data center load;
    - The DOM zone has been adjusted to account for growth in data center load;
    - The PS zone has been adjusted to account for growth in data center load and port electrification;

- The EKPC forecast has been adjusted to account for a peak shaving program that commenced in the 2023 DY;
- The AEP, ATSI, DAYTON, DEOK, PL, and PENLC forecasts have been adjusted to account for Non-Retail Behind-the-Meter Generation (NRBTMG) transitioning to participation as Demand Response in the Reliability Pricing Model.

- Summer peak load growth for the PJM RTO is projected to average 1.6% per year over the next 10-year period and 1.6% over the next 15 years. The PJM RTO summer peak is forecasted to be 176,822 MW in 2034, a 10-year increase of 25,575 MW, and reaches 190,752 MW in 2039, a 15-year increase of 39,505 MW. Annualized 10-year growth rates for individual zones range from 0% to 5.5%; median of 0.5%.

- Winter peak load growth for PJM RTO is projected to average 1.9% per year over the next 10-year period, and 1.8% over the next 15-years. The PJM RTO winter peak load in 2033/34 is forecasted to be 163,069 MW, a 10-year increase of 28,410 MW, and reaches 176,195 MW in 2038/39, a 15-year increase of 41,536 MW. Annualized 10-year growth rates for individual zones range from 0 % to 5.0%; median of 0.7%.

- Net energy for load growth for PJM RTO is projected to average 2.3% per year over the next 10-year period, and 2.2% over the next 15-years. Total PJM RTO energy is forecasted to be 1,021,955 GWh in 2034, a 10-year increase of 208,627 GWh, and reaches 1,120,928 GWh in 2039, a 15-year increase of 307,600 GWh. Annualized 10- year growth rates for individual zones range from 0.1% to 7.3%; median of 0.7%.

- Compared to the 2023 Load Report, the 2024 PJM RTO summer peak forecast shows the following changes for three years of interest:
  - The next delivery year – 2024 +1,510 MW (1.0%)
  - The next RPM auction year – 2025 +2,569 MW (1.7%)
  - The next RTEP study year – 2029 +8,758 MW (5.6%)

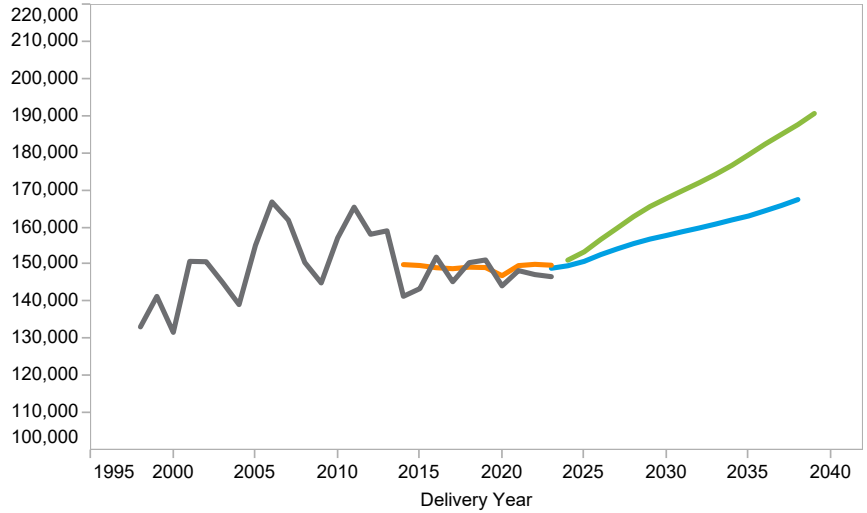
NOTE:

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 battery storage (in summer peak), additions for plug-in electric vehicles, and prior to reductions for load management impacts.

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

PJM RTO

Summer Peak



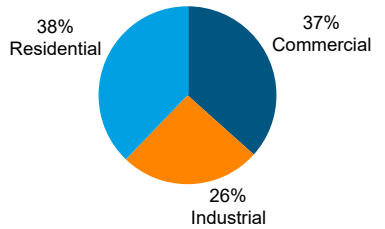
Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*74.25*
Avg Summer Max Temp	*95.13*
Avg Winter Daily Temp	*34.06*
Avg Winter Min Temp	*3.93*

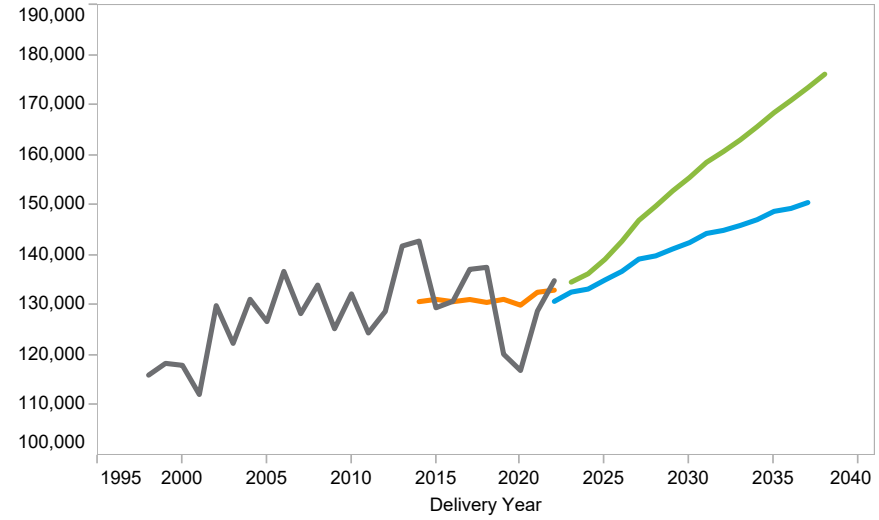
Zonal 10/15 Year Load Growth

SUMMER	1.6%	1.6%
WINTER	1.9%	1.8%

RCI Makeup



Winter Peak



LDAs

PJM Mid-Atlantic	Central MAAC
Eastern MAAC	Western MAAC
Southern MAAC	PJM West

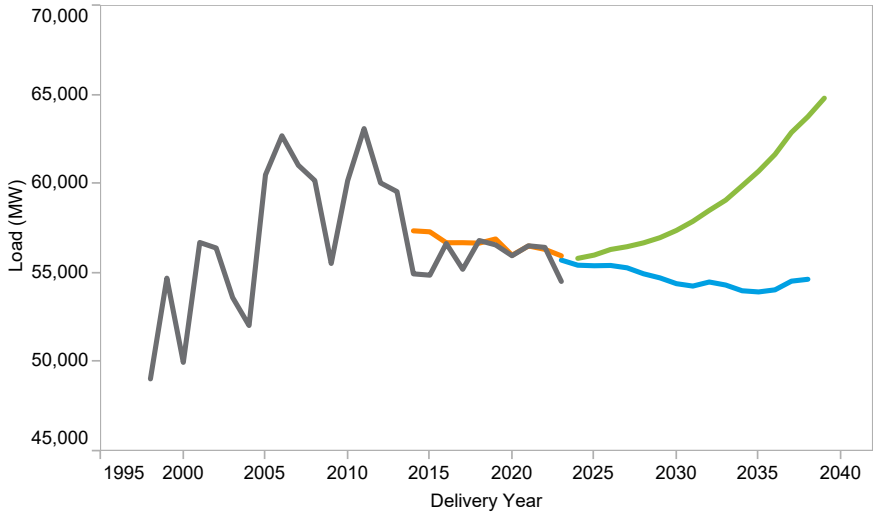
Zones

AE	DAYTON	JCPL	PEPCO
AEP	DEOK	METED	PL
APS	DLCO	OVEC	PS
ATSI	DOM	PECO	RECO
BGE	DPL	PENLC	UGI
COMED	EKPC		

Peak WN peak Forecast 2023 Forecast 2024

PJM Mid-Atlantic (MAAC)

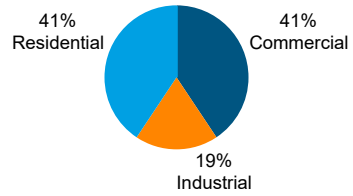
Summer Peak



Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*74.7*
Avg Summer Max Temp	*96.3*
Avg Winter Daily Temp	*34.9*
Avg Winter Min Temp	*6.5*

RCI Makeup



Zonal 10/15 Year Load Growth

SUMMER	0.7%	1.0%
WINTER	1.7%	1.7%

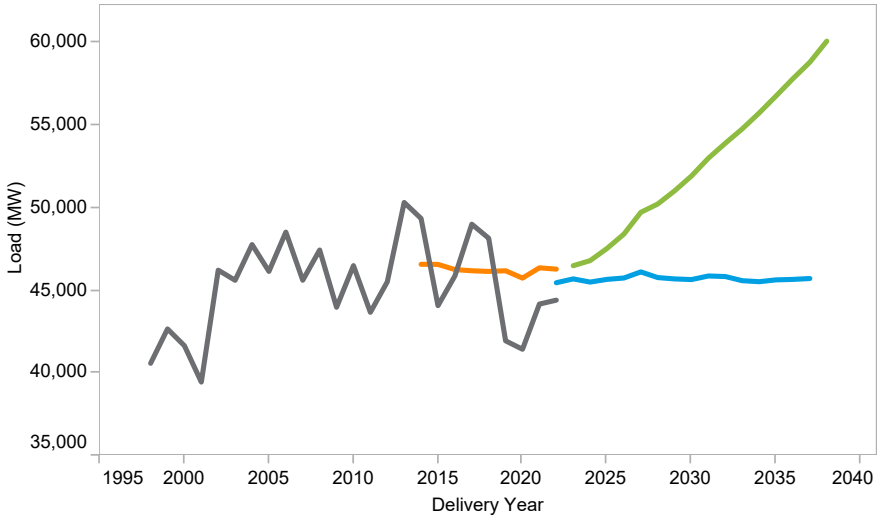
Zones

AE	JCPL	PENLC	PSEG
BGE	METED	PEPCO	RECO
DPL	PECO	PL	UGI

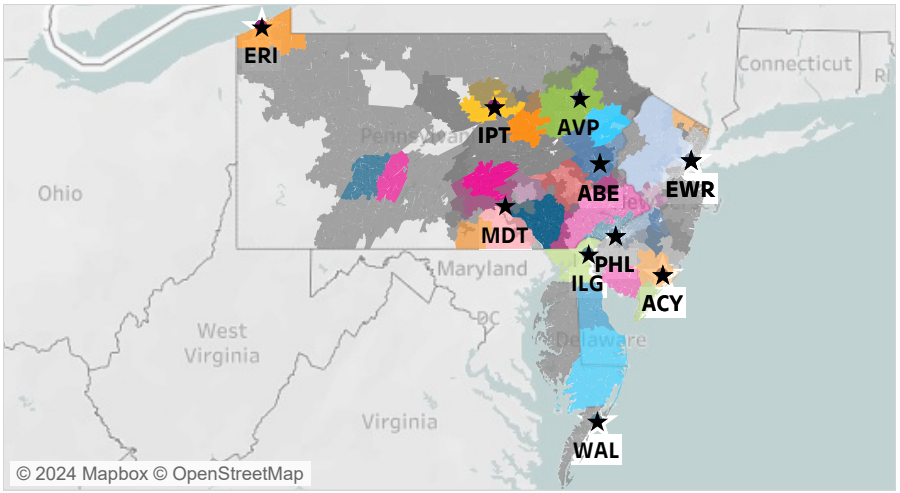
LDAs

E-MAAC	C-MAAC
S-MAAC	W-MAAC

Winter Peak



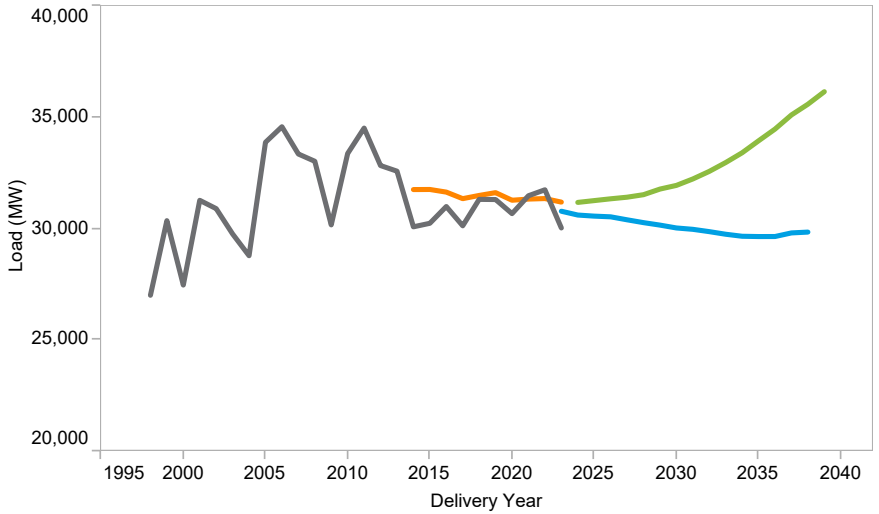
Metropolitan Statistical Areas and Weather Stations



Peak WN peak Forecast 2023 Forecast 2024

PJM Eastern Mid-Atlantic (E-MAAC)

Summer Peak



Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*75.7*
Avg Summer Max Temp	*97.5*
Avg Winter Daily Temp	*36.2*
Avg Winter Min Temp	*7.9*

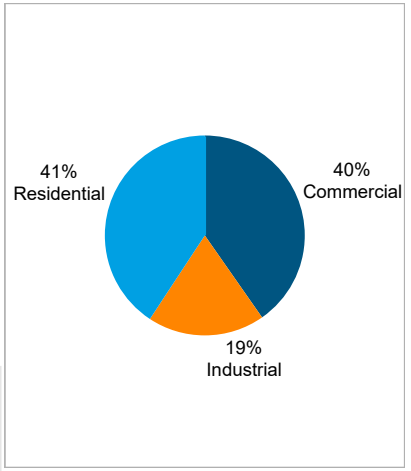
Zonal 10/15 Year Load Growth

SUMMER	0.7%	1.0%
WINTER	2.6%	2.5%

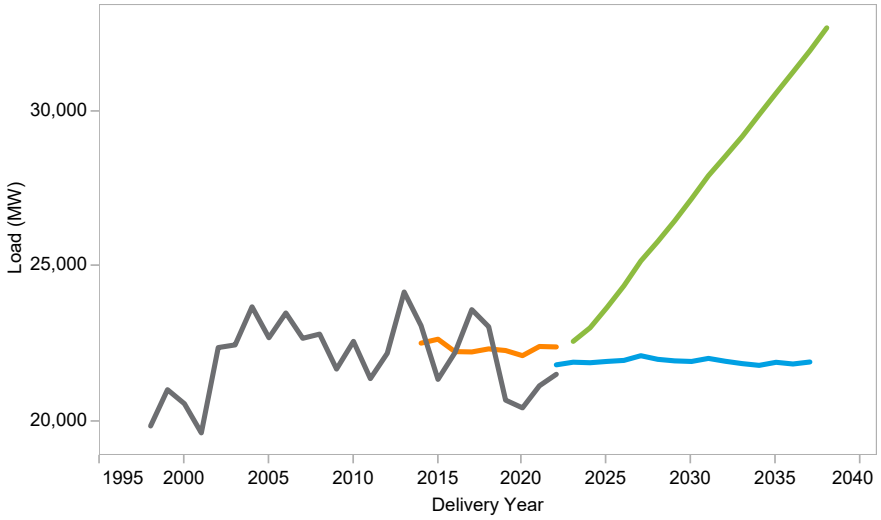
Zones

AE	PECO
DPL	PS
JCPL	RECO

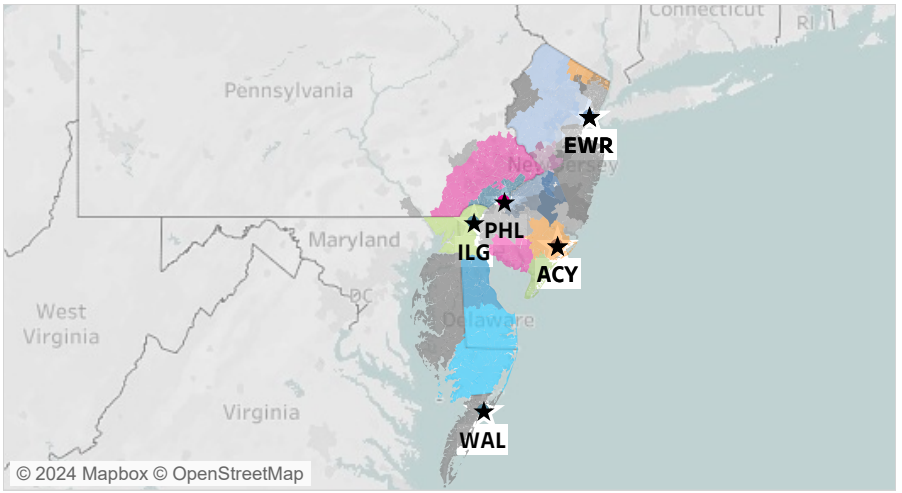
RCI Makeup



Winter Peak



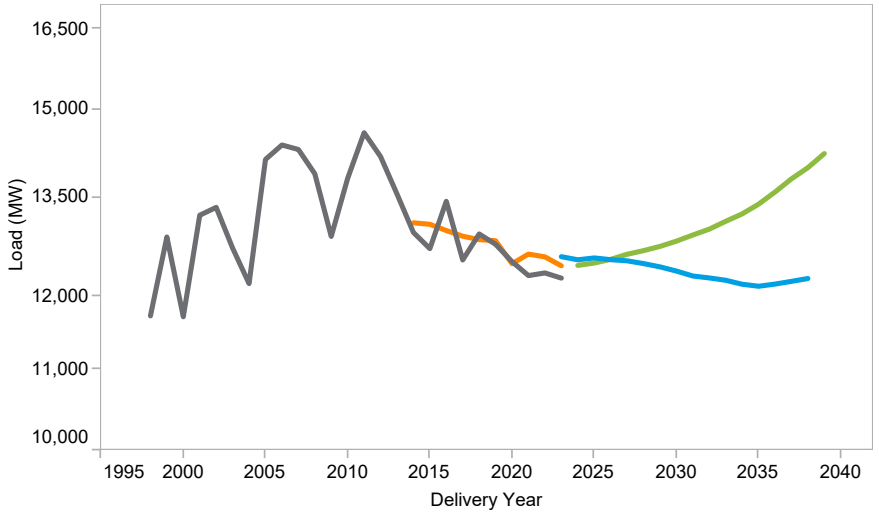
Metropolitan Statistical Areas and Weather Stations



Peak WN peak Forecast 2023 Forecast 2024

PJM Southern Mid-Atlantic (S-MAAC)

Summer Peak



Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*77.1*
Avg Summer Max Temp	*98.0*
Avg Winter Daily Temp	*37.9*
Avg Winter Min Temp	*10.3*

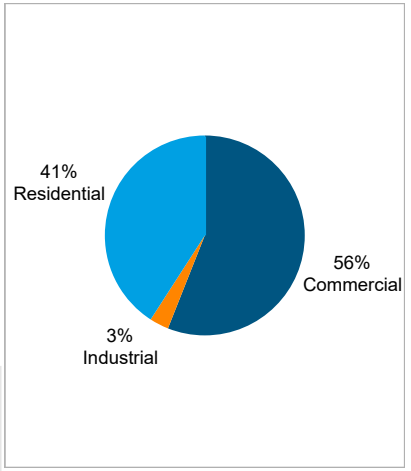
Zonal 10/15 Year Load Growth

SUMMER	0.6%	0.9%
WINTER	0.7%	0.9%

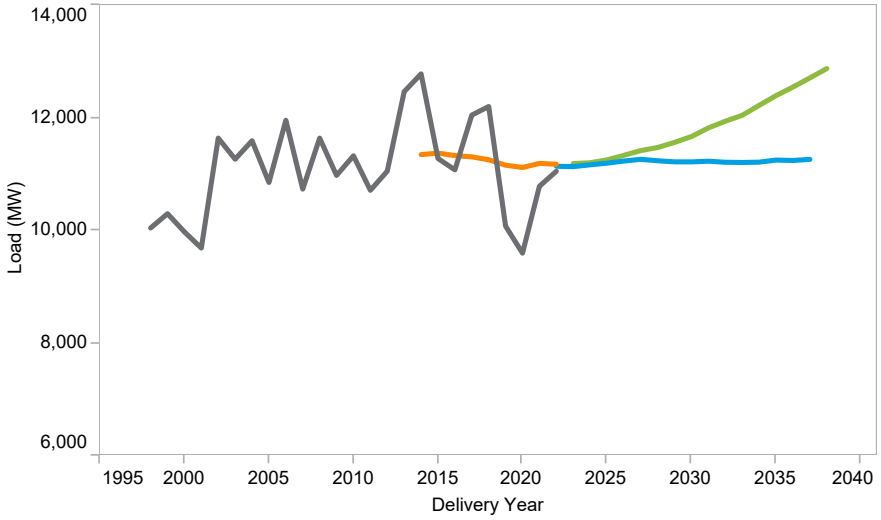
Zones

BGE PEPCO

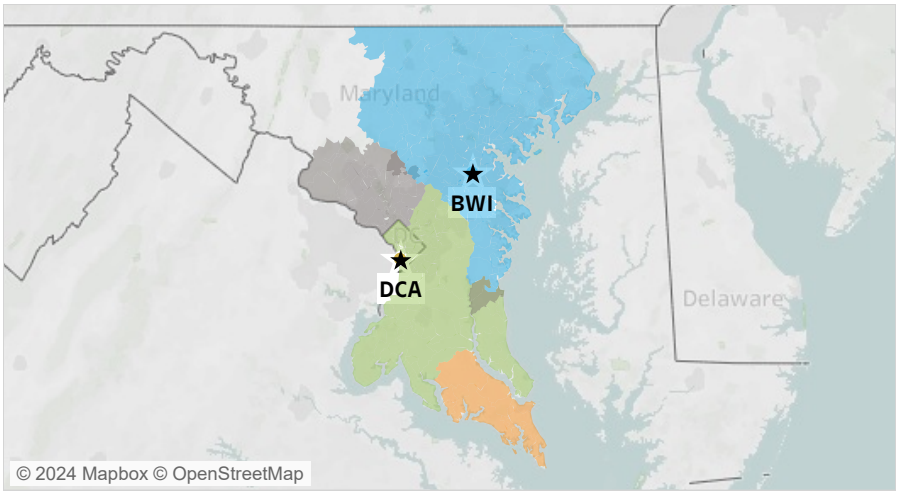
RCI Makeup



Winter Peak



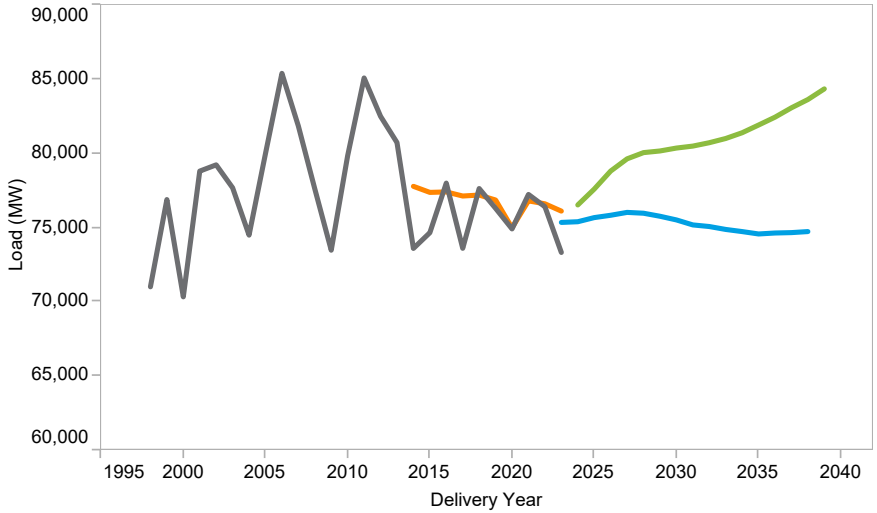
Metropolitan Statistical Areas and Weather Stations



Peak WN peak Forecast 2023 Forecast 2024

PJM Western

Summer Peak



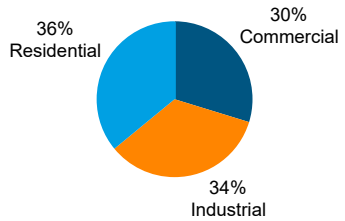
Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*73.2*
Avg Summer Max Temp	*93.2*
Avg Winter Daily Temp	*32.0*
Avg Winter Min Temp	*-1.0*

Zonal 10/15 Year Load Growth

SUMMER	0.6%	0.7%
WINTER	0.9%	0.8%

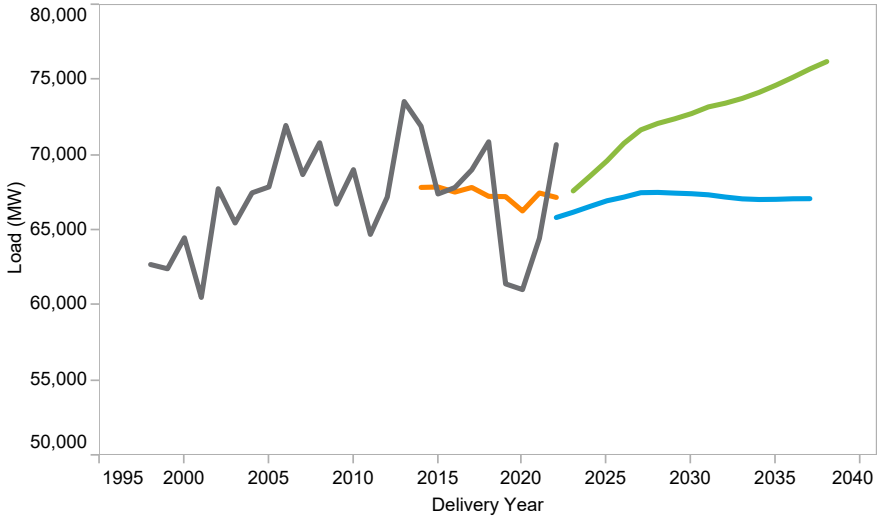
RCI Makeup



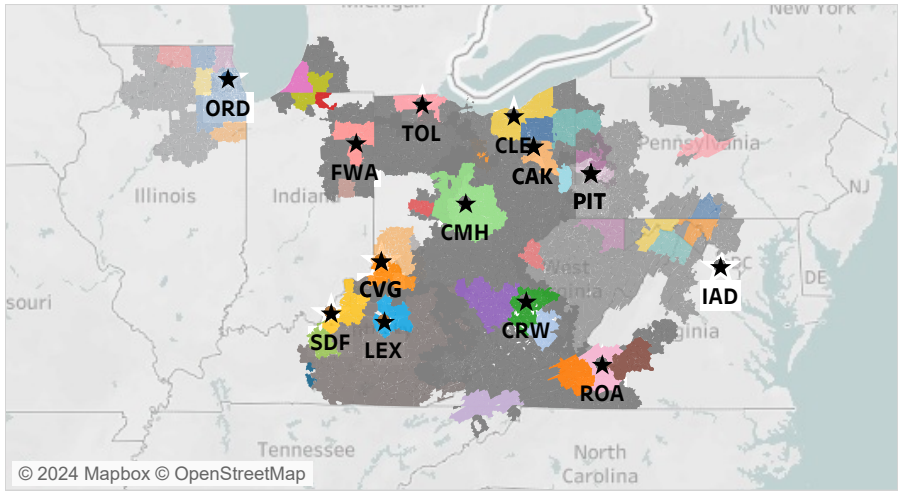
Zones

AEP	COMED	DLCO
APS	DAYTON	EKPC
ATSI	DEOK	OVEC

Winter Peak



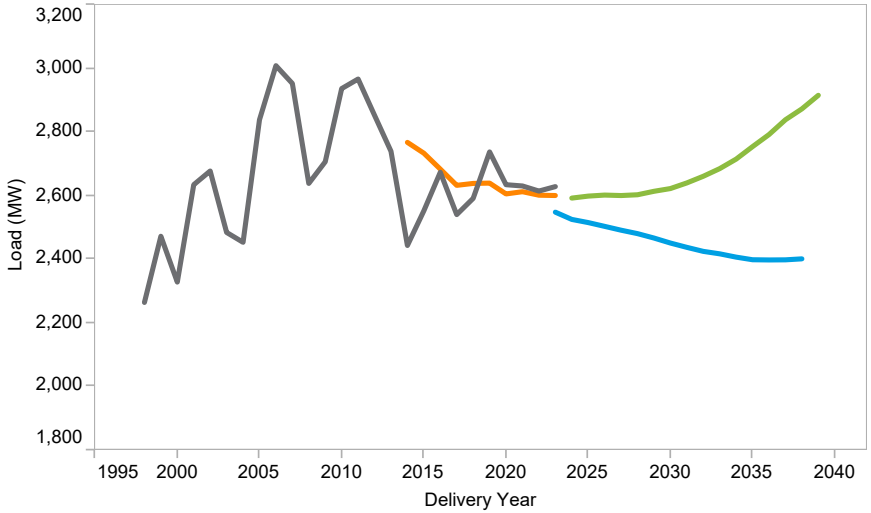
Metropolitan Statistical Areas and Weather Stations



Peak WN peak Forecast 2023 Forecast 2024

Atlantic Electric (AE)

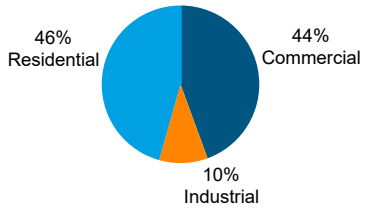
Summer Peak



Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*74.4*
Avg Summer Max Temp	*97.0*
Avg Winter Daily Temp	*36.6*
Avg Winter Min Temp	*6.0*

RCI Makeup



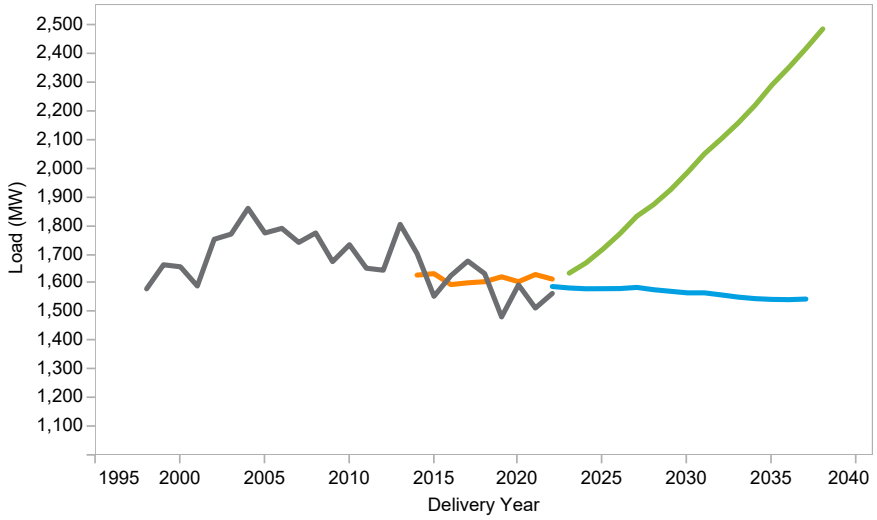
Zonal 10/15 Year Load Growth

SUMMER	0.5%	0.8%
WINTER	2.8%	2.8%

LDAs

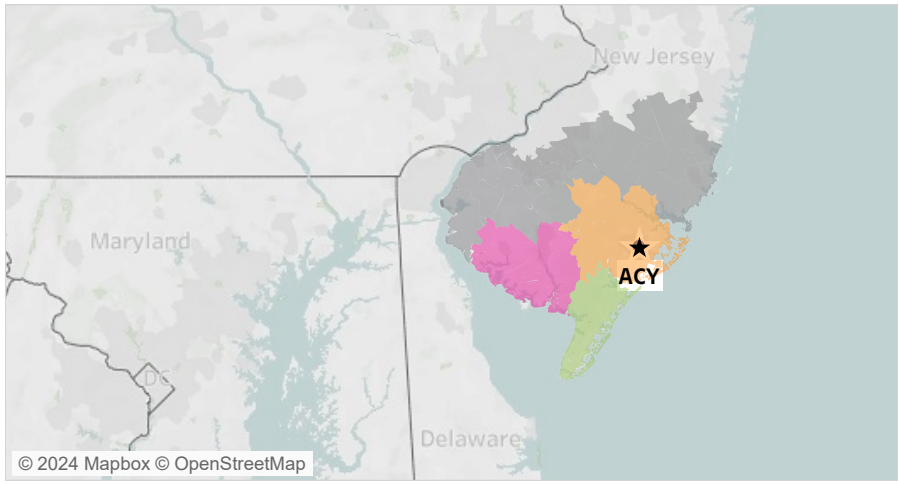
EASTERN MID-ATLANTIC PJM MID-ATLANTIC PJM RTO

Winter Peak



Peak WN peak Forecast 2023 Forecast 2024

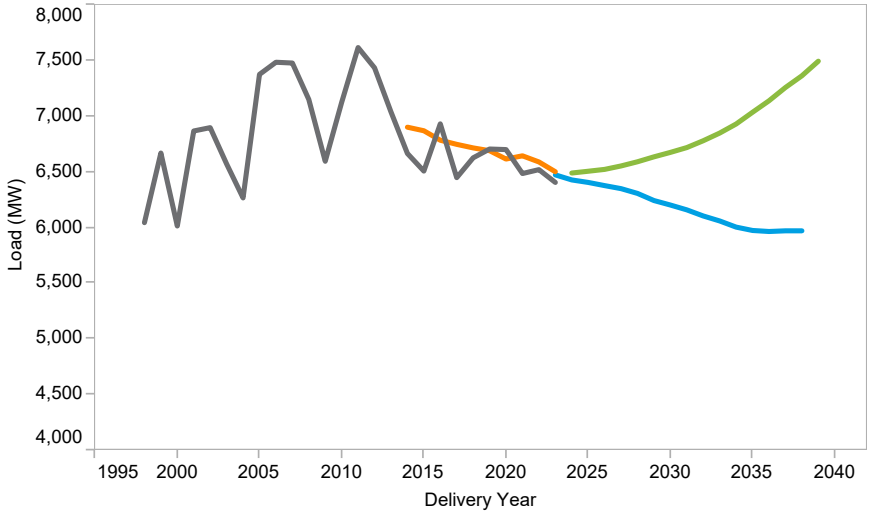
Metropolitan Statistical Areas and Weather Stations



AE - Non-Metro
Atlantic City-Hammonton, NJ
Ocean City, NJ
Vineland-Bridgeton, NJ

Baltimore Gas and Electric (BGE)

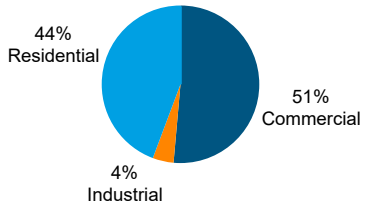
Summer Peak



Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*76.0*
Avg Summer Max Temp	*98.0*
Avg Winter Daily Temp	*36.7*
Avg Winter Min Temp	*7.8*

RCI Makeup



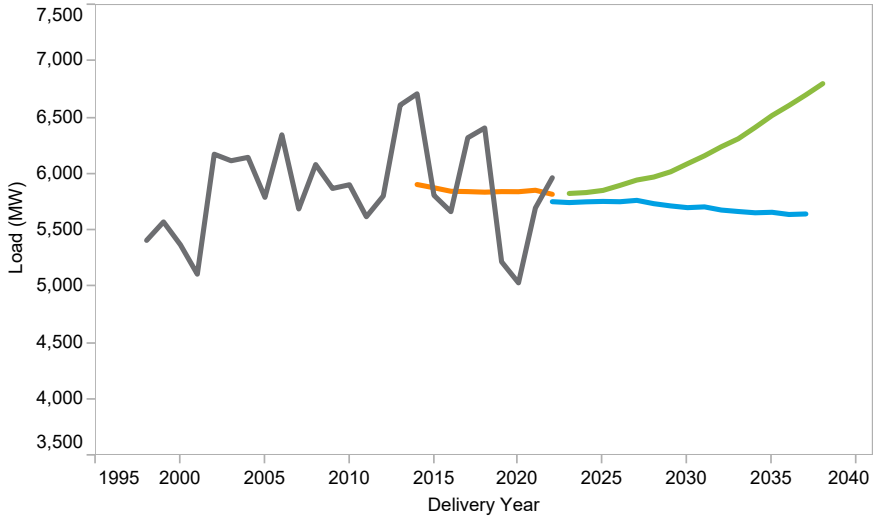
Zonal 10/15 Year Load Growth

SUMMER	0.7%	1.0%
WINTER	0.8%	1.0%

LDAs

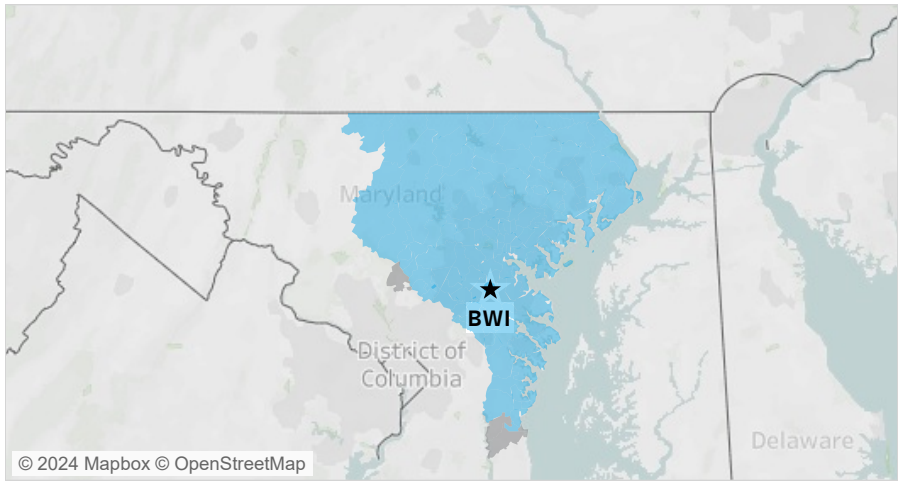
CENTRAL MID-ATLANTIC PJM MID-ATLANTIC PJM RTO
SOUTHERN MID-ATLANTIC

Winter Peak



Peak WN peak Forecast 2023 Forecast 2024

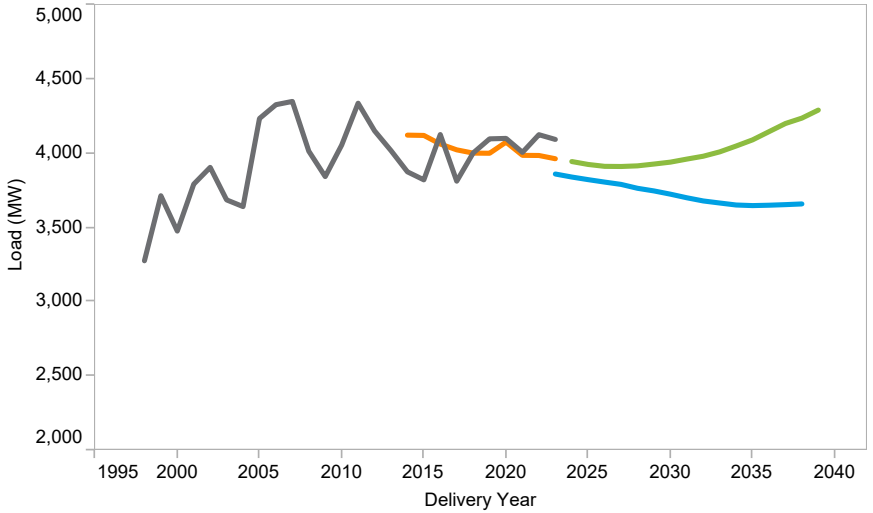
Metropolitan Statistical Areas and Weather Stations



Baltimore-Columbia-Towson, MD
BGE - Non-Metro

Delmarva Power and Light (DPL)

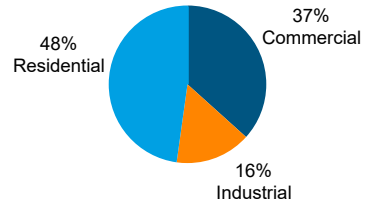
Summer Peak



Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*75.5*
Avg Summer Max Temp	*95.0*
Avg Winter Daily Temp	*37.0*
Avg Winter Min Temp	*9.7*

RCI Makeup



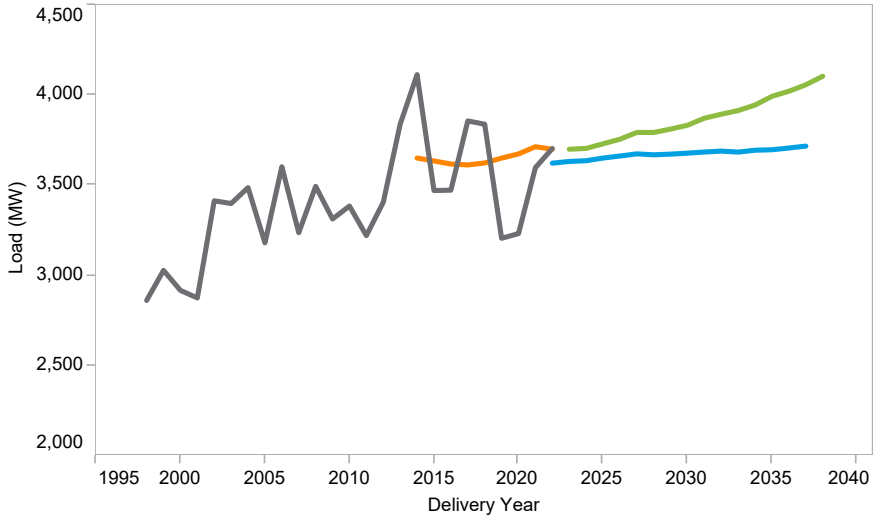
Zonal 10/15 Year Load Growth

SUMMER	0.3%	0.6%
WINTER	0.6%	0.7%

LDAs

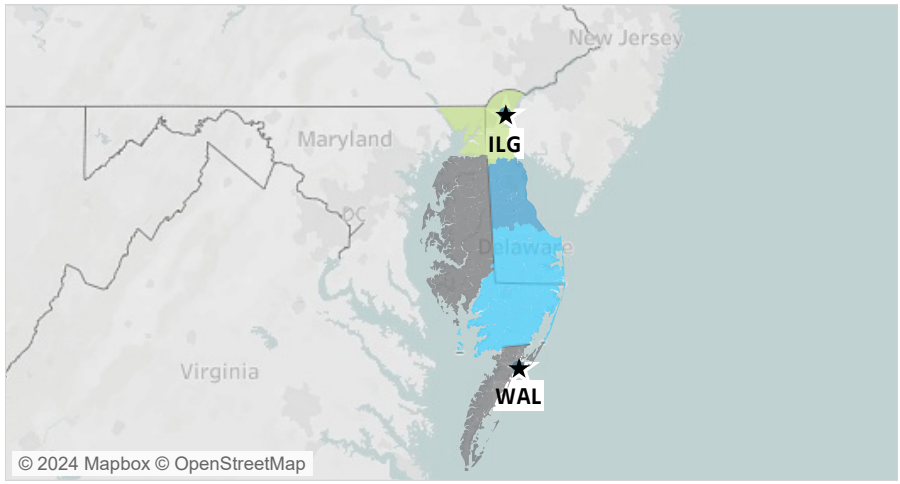
EASTERN MID-ATLANTIC PJM MID-ATLANTIC PJM RTO

Winter Peak



Peak WN peak Forecast 2023 Forecast 2024

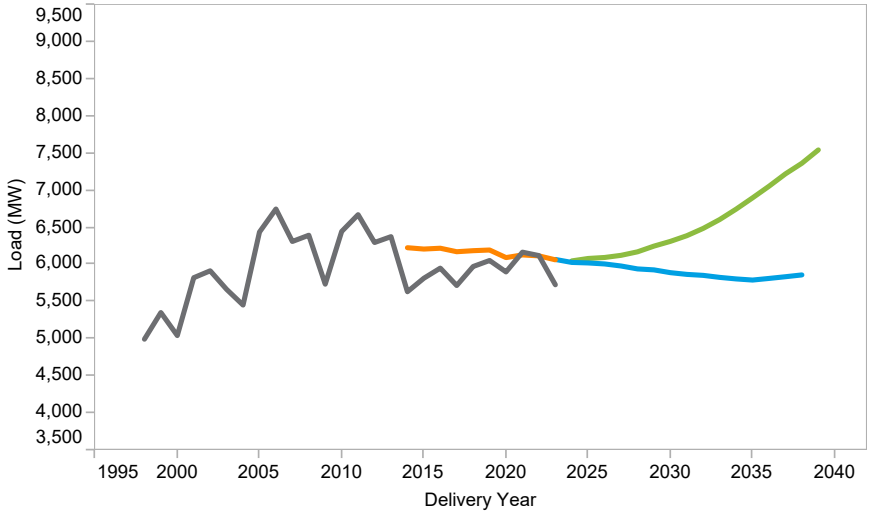
Metropolitan Statistical Areas and Weather Stations



Dover, DE
DPL - Non-Metro
Salisbury, MD-DE
Wilmington, DE-MD-NJ

Jersey Central Power and Light (JCPL)

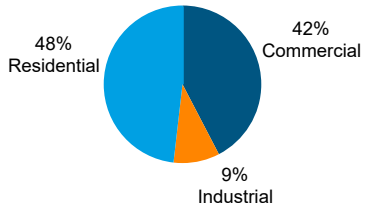
Summer Peak



Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*75.6*
Avg Summer Max Temp	*98.0*
Avg Winter Daily Temp	*35.8*
Avg Winter Min Temp	*7.6*

RCI Makeup



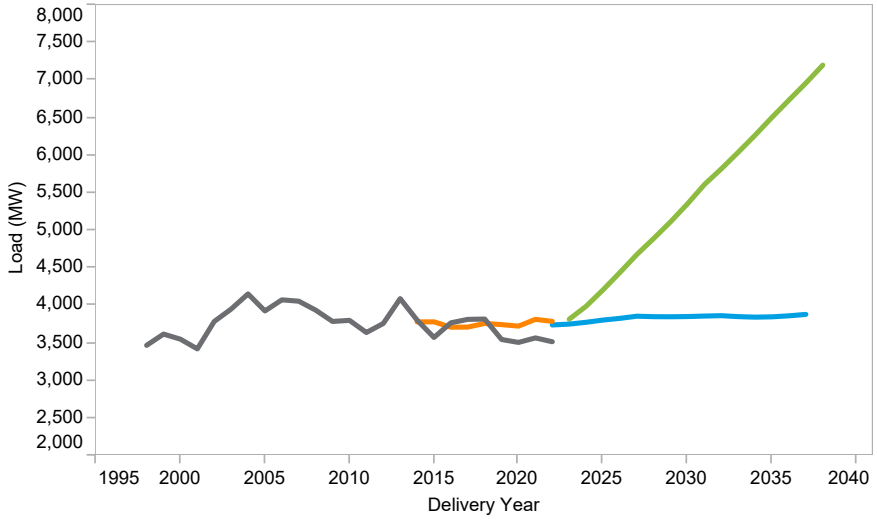
Zonal 10/15 Year Load Growth

SUMMER	1.1%	1.5%
WINTER	4.7%	4.3%

LDAs

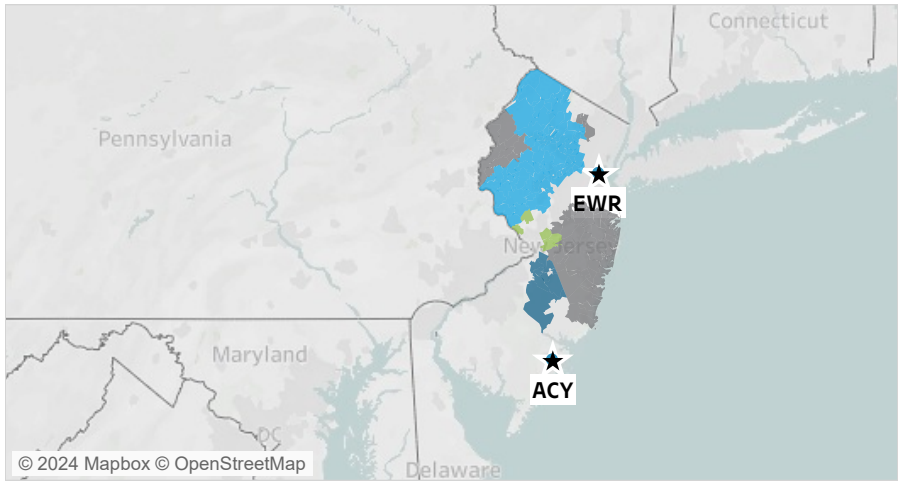
EASTERN MID-ATLANTIC GPU PJM MID-ATLANTIC PJM RTO

Winter Peak



Peak WN peak Forecast 2023 Forecast 2024

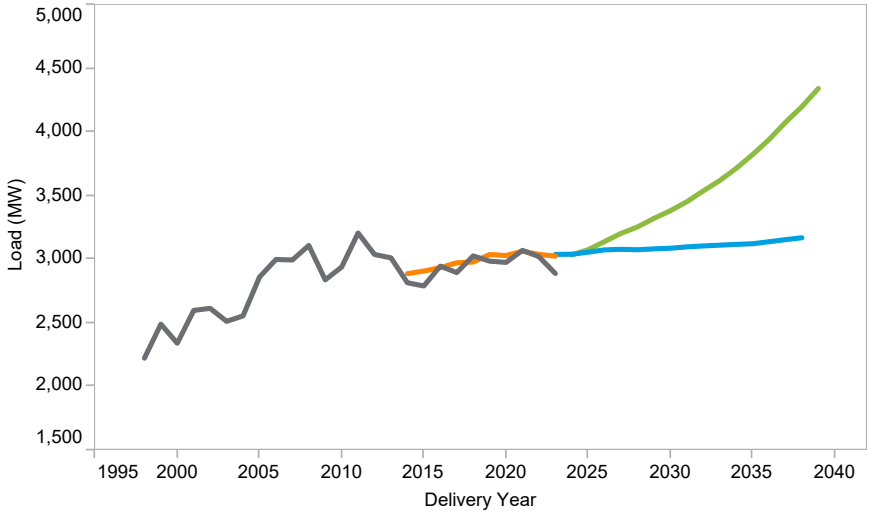
Metropolitan Statistical Areas and Weather Stations



Camden, NJ
JCPL - Non-Metro
Newark, NJ-PA
Trenton, NJ

Metropolitan Edison (METED)

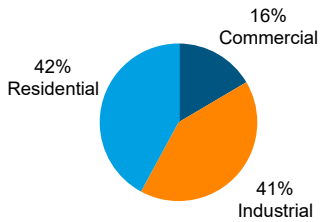
Summer Peak



Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*74.7*
Avg Summer Max Temp	*95.8*
Avg Winter Daily Temp	*34.4*
Avg Winter Min Temp	*6.6*

RCI Makeup



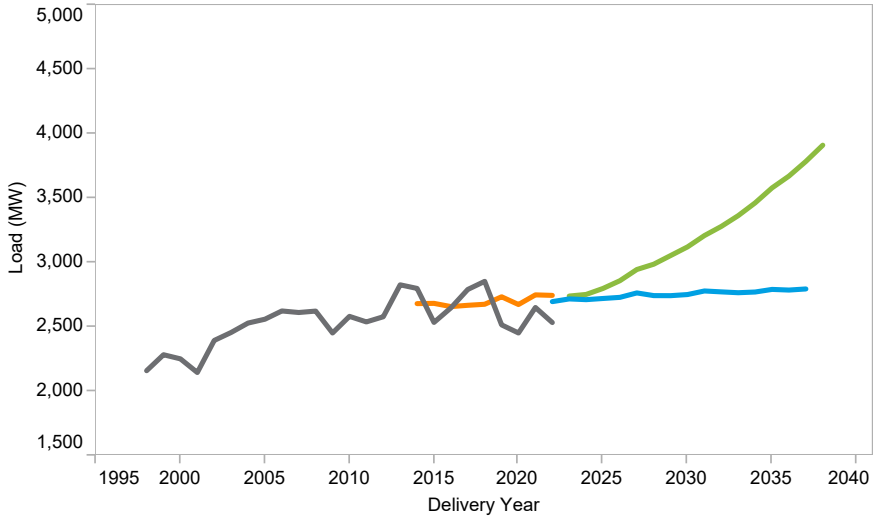
Zonal 10/15 Year Load Growth

SUMMER	2.0%	2.4%
WINTER	2.1%	2.4%

LDAs

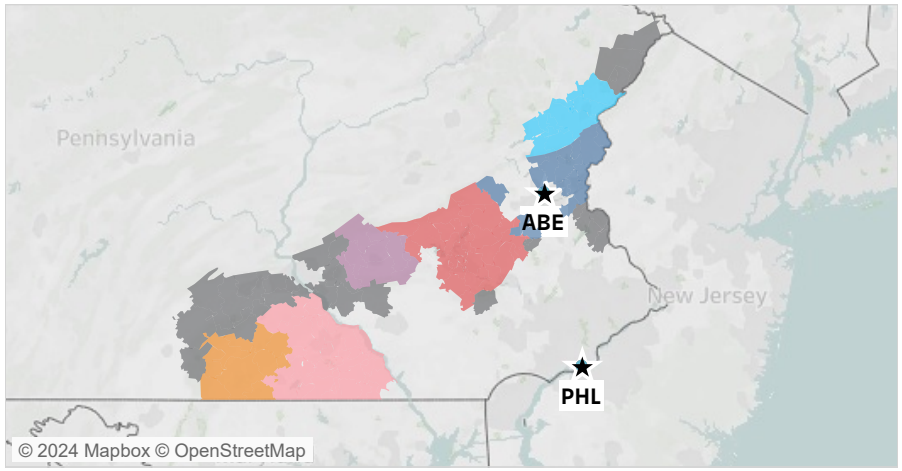
CENTRAL MID-ATLANTIC GPU PJM MID-ATLANTIC PJM RTO WESTERN MID-ATLANTIC

Winter Peak



Peak WN peak Forecast 2023 Forecast 2024

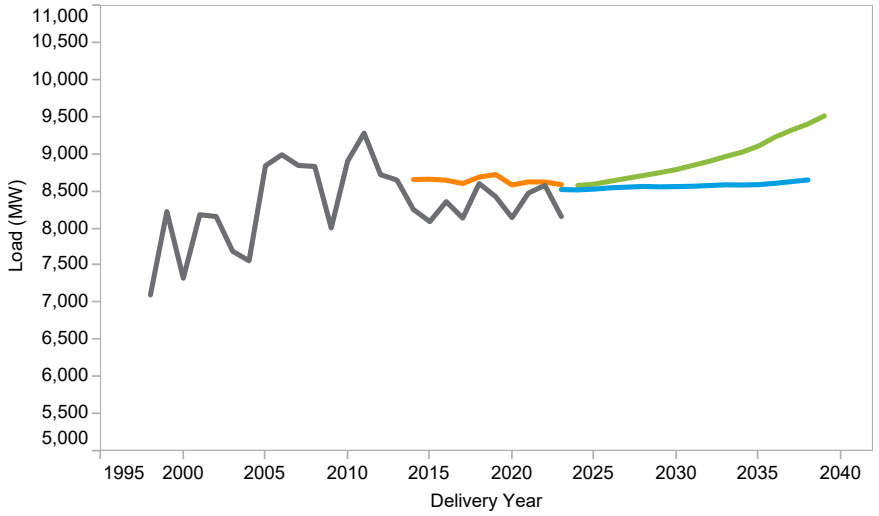
Metropolitan Statistical Areas and Weather Stations



- Allentown-Bethlehem-Easton, PA-NJ
- East Stroudsburg, PA
- Gettysburg, PA
- Lebanon, PA
- METED - Non-Metro
- Reading, PA
- York-Hanover, PA

PECO Energy (PECO)

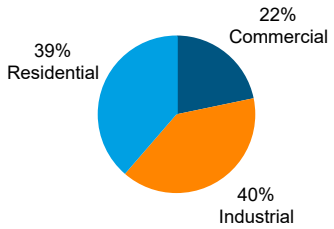
Summer Peak



Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*76.6*
Avg Summer Max Temp	*97.1*
Avg Winter Daily Temp	*36.6*
Avg Winter Min Temp	*9.2*

RCI Makeup



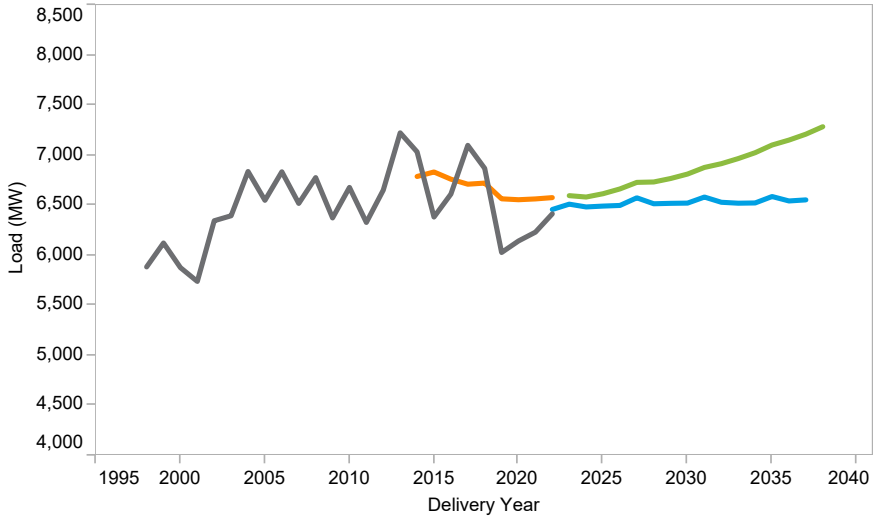
Zonal 10/15 Year Load Growth

SUMMER	0.5%	0.7%
WINTER	0.5%	0.7%

LDAs

EASTERN MID-ATLANTIC PJM MID-ATLANTIC PJM RTO

Winter Peak



Peak WN peak Forecast 2023 Forecast 2024

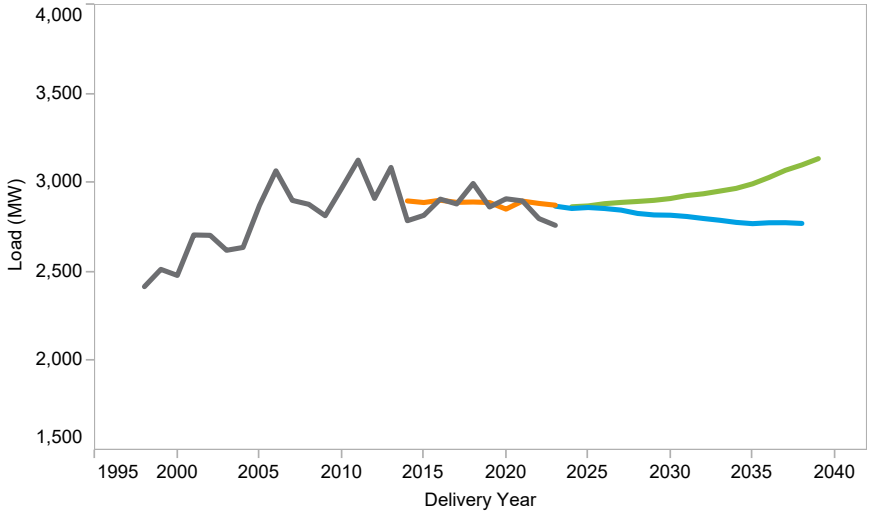
Metropolitan Statistical Areas and Weather Stations



Montgomery County-Bucks County-Chester County, PA
PECO - Non-Metro
Philadelphia, PA

Pennsylvania Electric Company (PENLC)

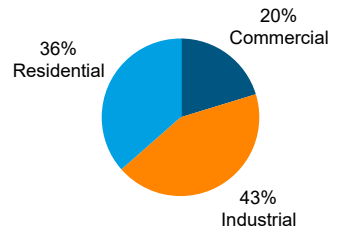
Summer Peak



Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*71.1*
Avg Summer Max Temp	*91.6*
Avg Winter Daily Temp	*30.3*
Avg Winter Min Temp	*2.0*

RCI Makeup



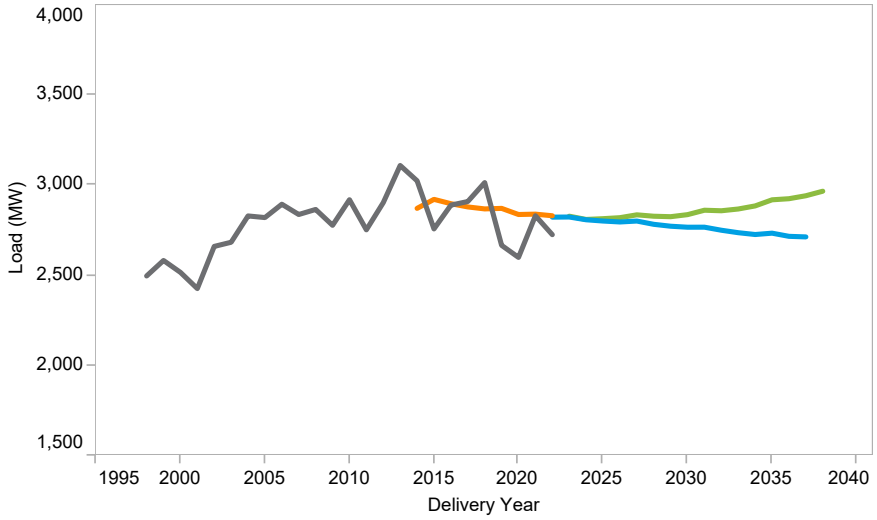
Zonal 10/15 Year Load Growth

SUMMER	0.4%	0.6%
WINTER	0.1%	0.3%

LDAs

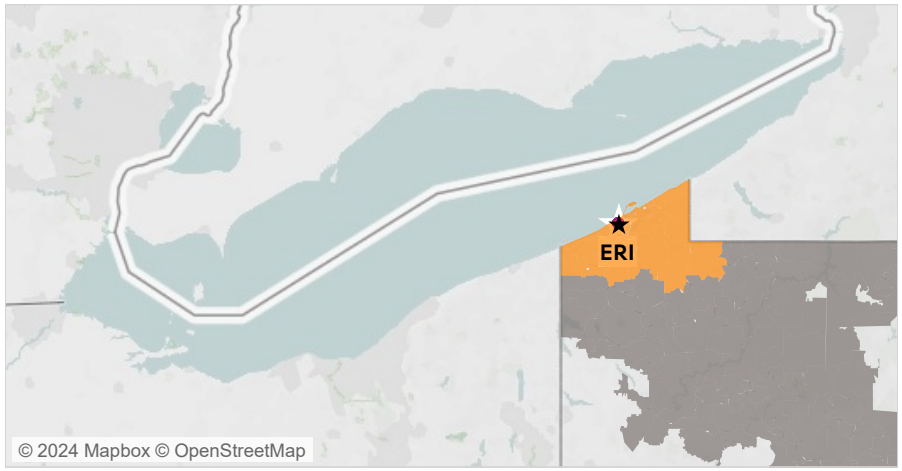
GPU PJM MID-ATLANTIC PJM RTO WESTERN MID-ATLANTIC

Winter Peak



Peak WN peak Forecast 2023 Forecast 2024

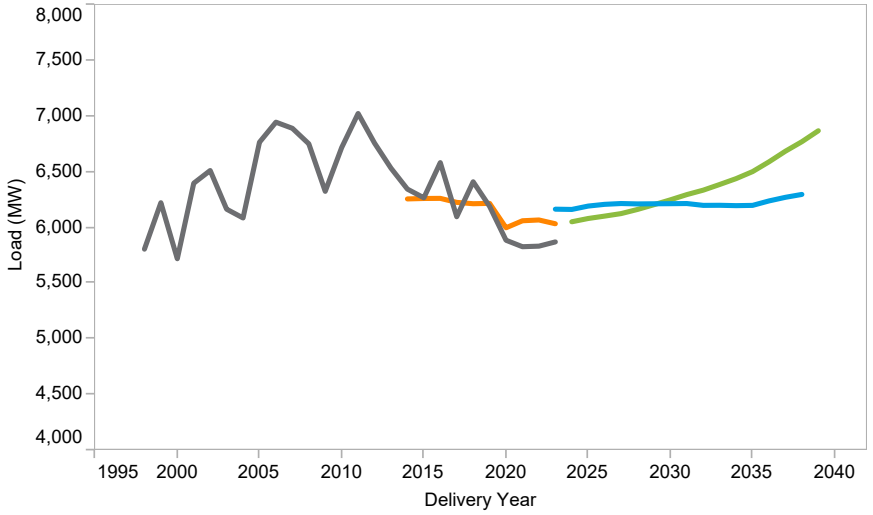
Metropolitan Statistical Areas and Weather Stations



Altoona, PA
Erie, PA
Johnstown, PA
PENLC - Non-Metro

Potomac Electric Power (PEPCO)

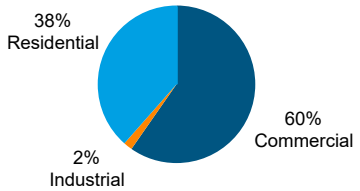
Summer Peak



Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*78.1*
Avg Summer Max Temp	*98.0*
Avg Winter Daily Temp	*39.0*
Avg Winter Min Temp	*12.8*

RCI Makeup



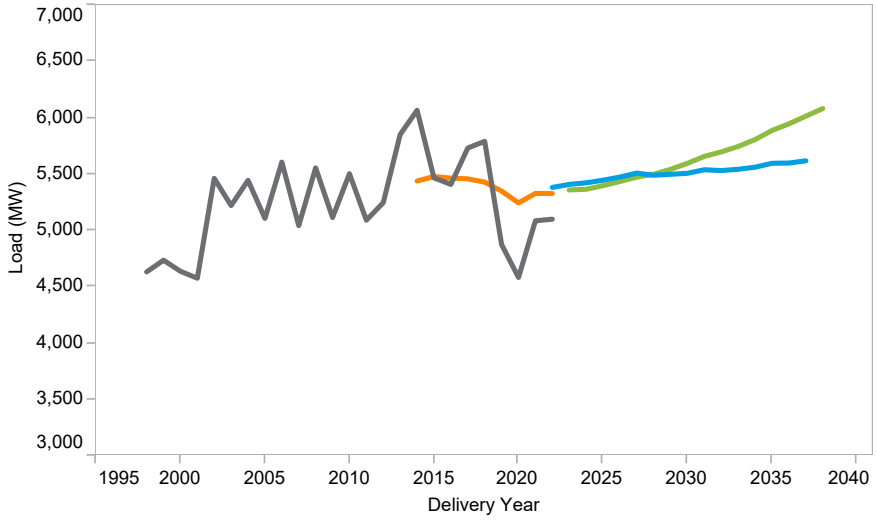
Zonal 10/15 Year Load Growth

SUMMER	0.6%	0.8%
WINTER	0.7%	0.8%

LDAs

CENTRAL MID-ATLANTIC PJM MID-ATLANTIC PJM RTO
SOUTHERN MID-ATLANTIC

Winter Peak



Peak WN peak Forecast 2023 Forecast 2024

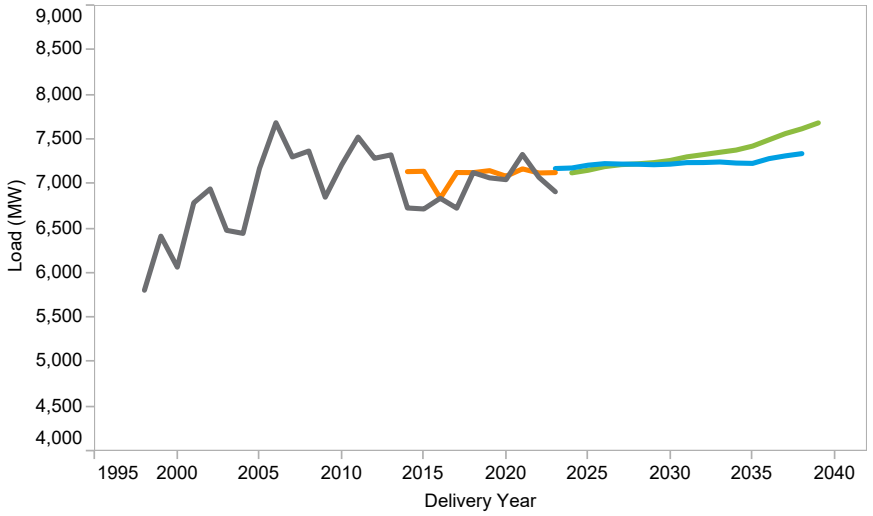
Metropolitan Statistical Areas and Weather Stations



California-Lexington Park, MD
PEPCO - Non-Metro
Washington-Arlington-Alexandria, DC-VA-MD-WV

PPL Electric Utilities (PL)

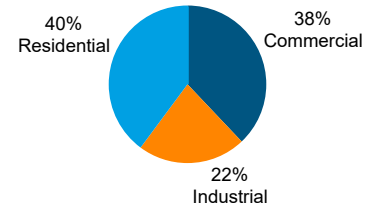
Summer Peak



Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*72.4*
Avg Summer Max Temp	*94.2*
Avg Winter Daily Temp	*31.5*
Avg Winter Min Temp	*2.8*

RCI Makeup



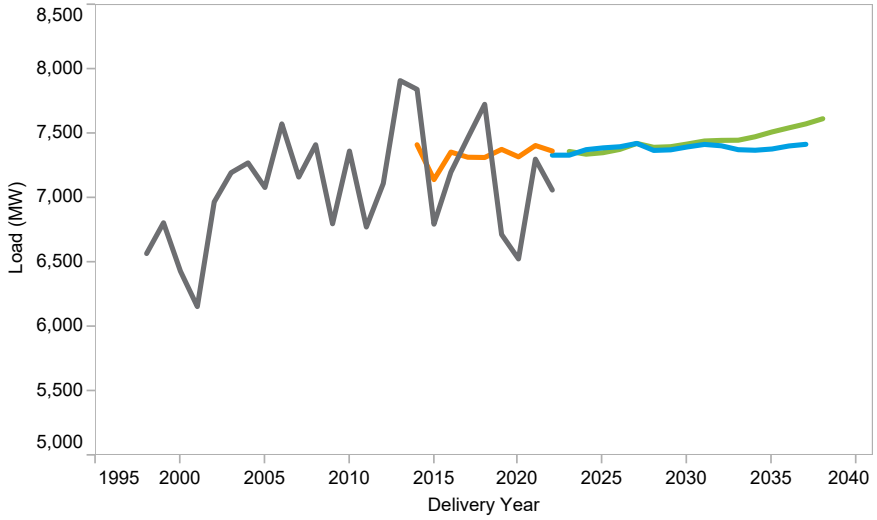
Zonal 10/15 Year Load Growth

SUMMER	0.4%	0.5%
WINTER	0.1%	0.2%

LDAs

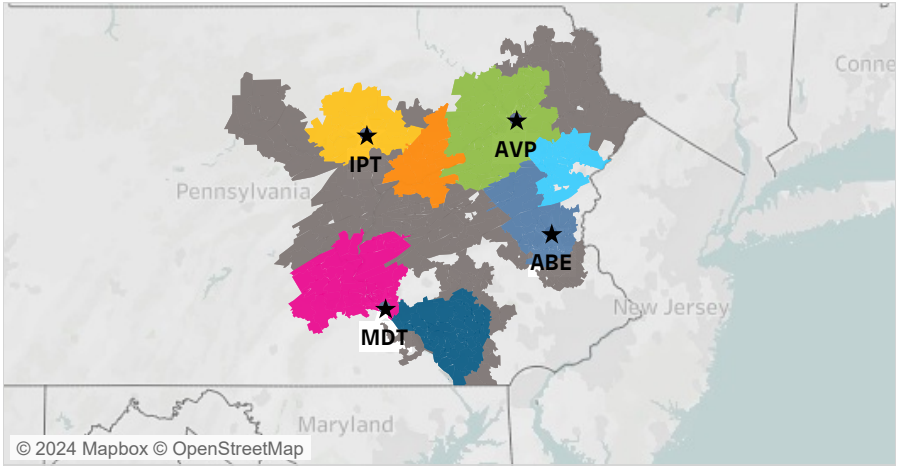
CENTRAL MID-ATLANTIC PJM MID-ATLANTIC PJM RTO
PLGRP WESTERN MID-ATLANTIC

Winter Peak



Peak WN peak Forecast 2023 Forecast 2024

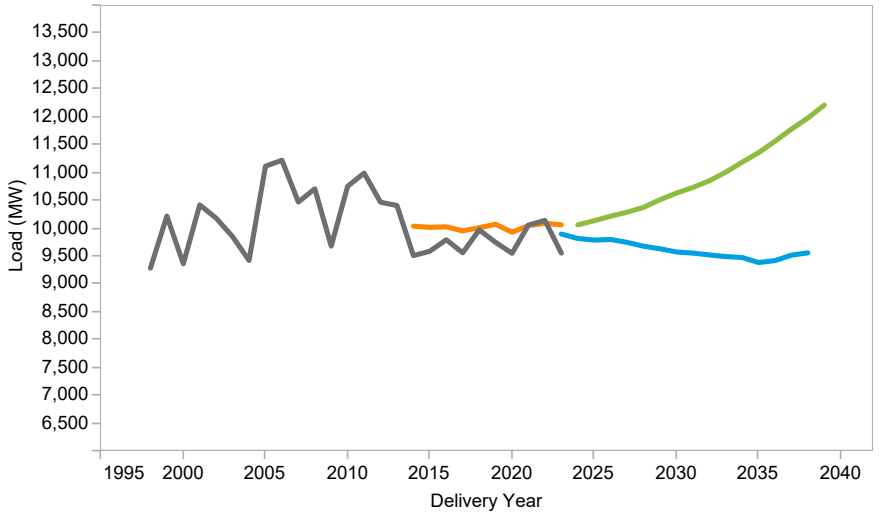
Metropolitan Statistical Areas and Weather Stations



Allentown-Bethlehem-Easton, PA-NJ
Bloomsburg-Berwick, PA
East Stroudsburg, PA
Harrisburg-Carlisle, PA
Lancaster, PA
PL - Non-Metro
Scranton--Wilkes-Barre--Hazleton, PA
Williamsport, PA

Public Service Electric & Gas (PS)

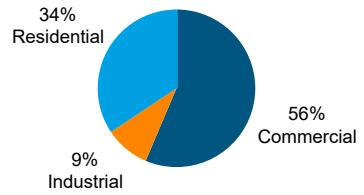
Summer Peak



Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*76.0*
Avg Summer Max Temp	*98.8*
Avg Winter Daily Temp	*35.6*
Avg Winter Min Temp	*7.5*

RCI Makeup



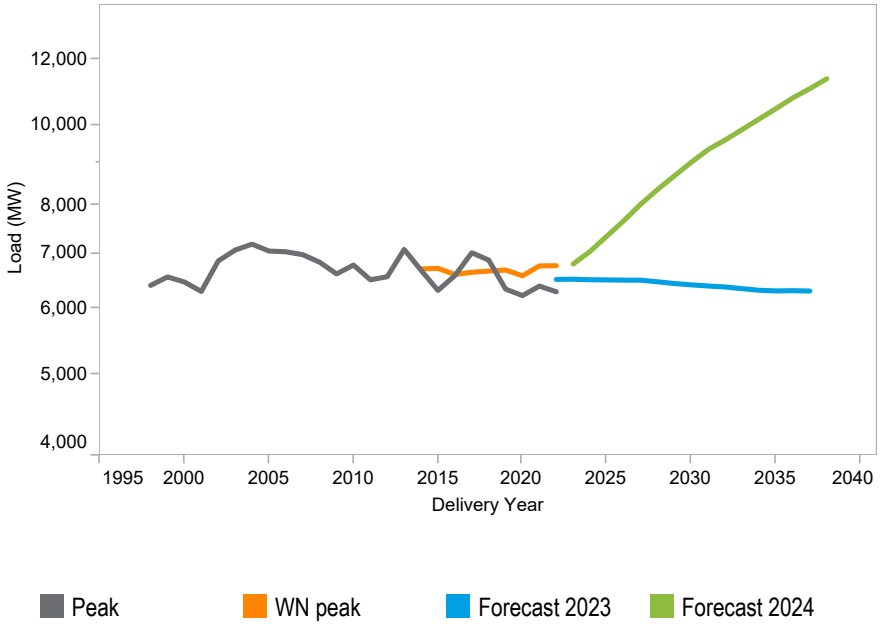
Zonal 10/15 Year Load Growth

SUMMER	1.1%	1.3%
WINTER	3.8%	3.5%

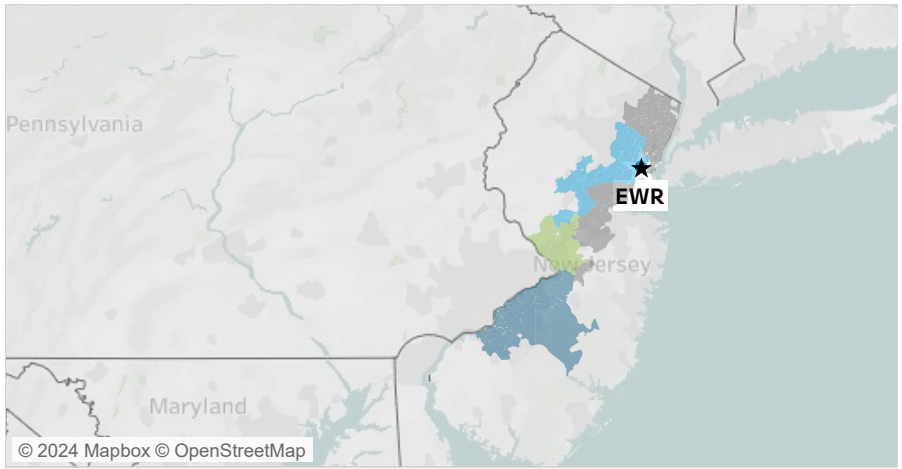
LDAs

EASTERN MID-ATLANTIC PJM MID-ATLANTIC PJM RTO

Winter Peak



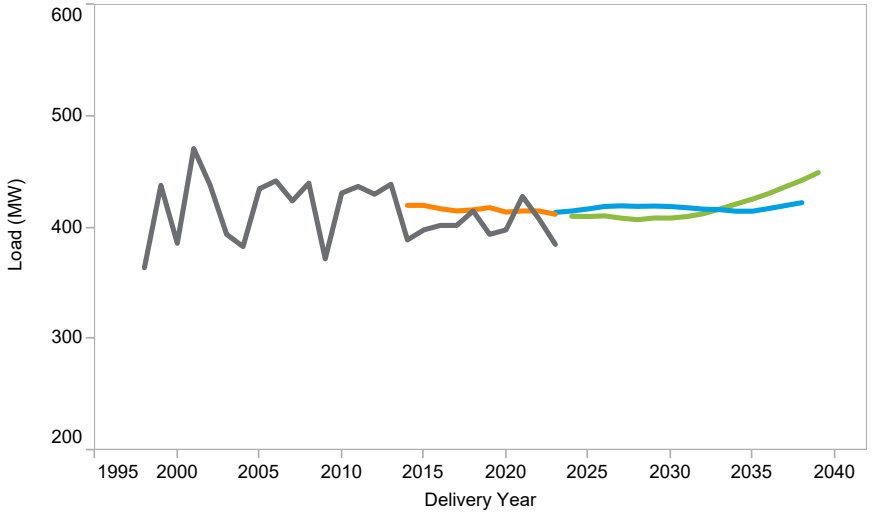
Metropolitan Statistical Areas and Weather Stations



Camden, NJ
Newark, NJ-PA
PS - Non-Metro
Trenton, NJ

Rockland Electric Company (RECO)

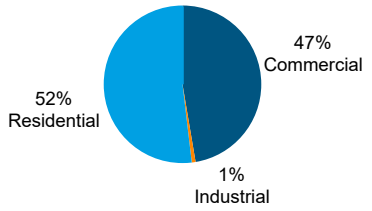
Summer Peak



Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*76.0*
Avg Summer Max Temp	*98.8*
Avg Winter Daily Temp	*35.6*
Avg Winter Min Temp	*7.5*

RCI Makeup



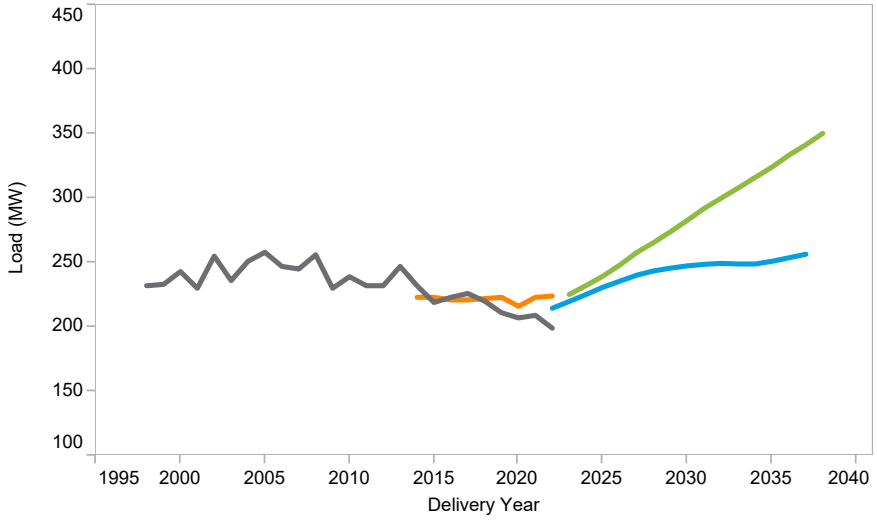
Zonal 10/15 Year Load Growth

SUMMER	0.3%	0.6%
WINTER	3.2%	3.0%

LDAs

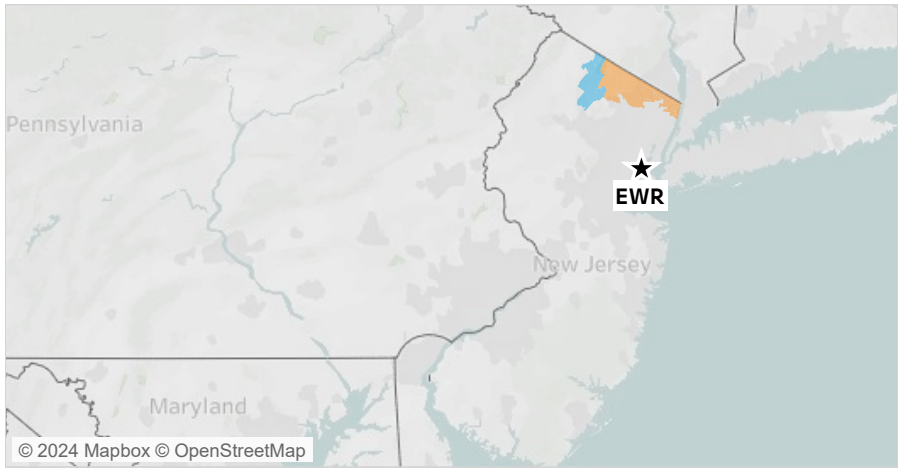
EASTERN MID-ATLANTIC PJM MID-ATLANTIC PJM RTO

Winter Peak



Peak WN peak Forecast 2023 Forecast 2024

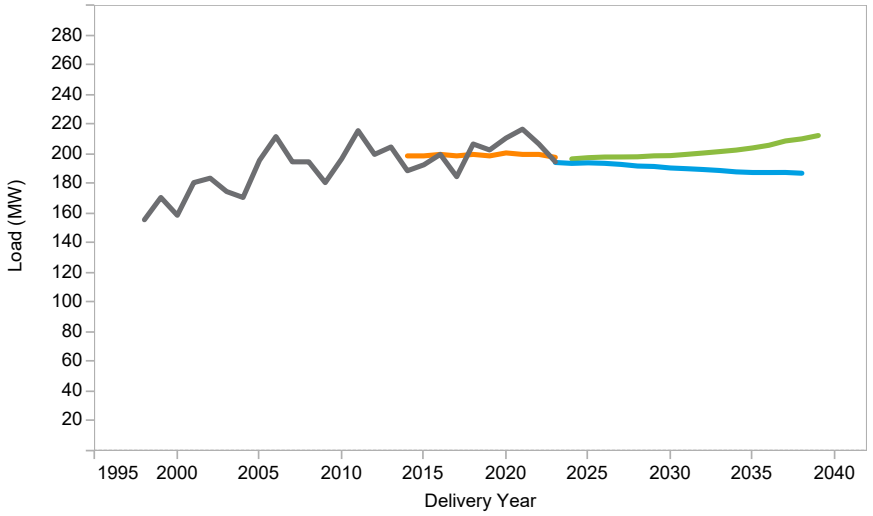
Metropolitan Statistical Areas and Weather Stations



New York-Jersey City-White Plains, NY-NJ
Newark, NJ-PA

UGI Energy Services (UGI)

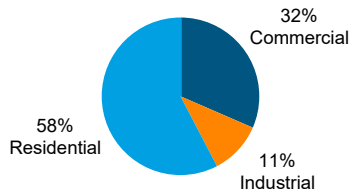
Summer Peak



Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*70.6*
Avg Summer Max Temp	*93.2*
Avg Winter Daily Temp	*30.1*
Avg Winter Min Temp	*-1.0*

RCI Makeup



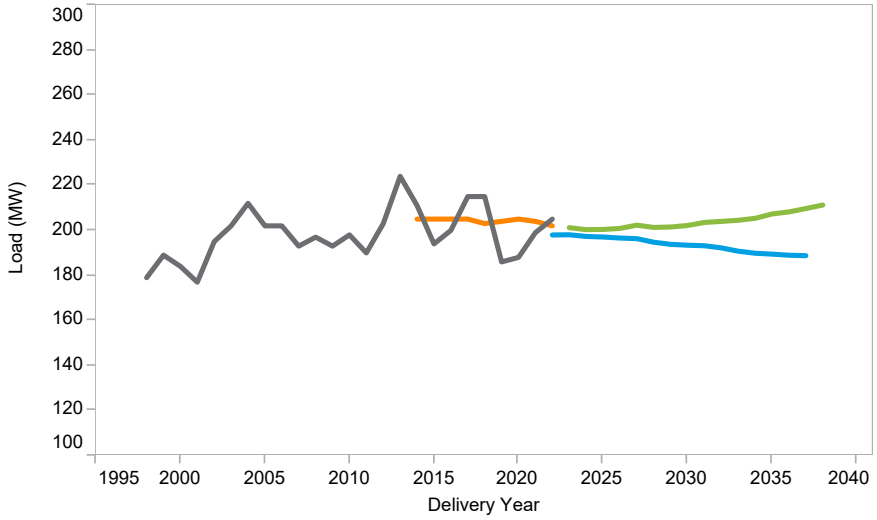
Zonal 10/15 Year Load Growth

SUMMER	0.3%	0.5%
WINTER	0.2%	0.3%

LDAs

CENTRAL MID-ATLANTIC PJM MID-ATLANTIC PJM RTO
PLGRP WESTERN MID-ATLANTIC

Winter Peak



Metropolitan Statistical Areas and Weather Stations

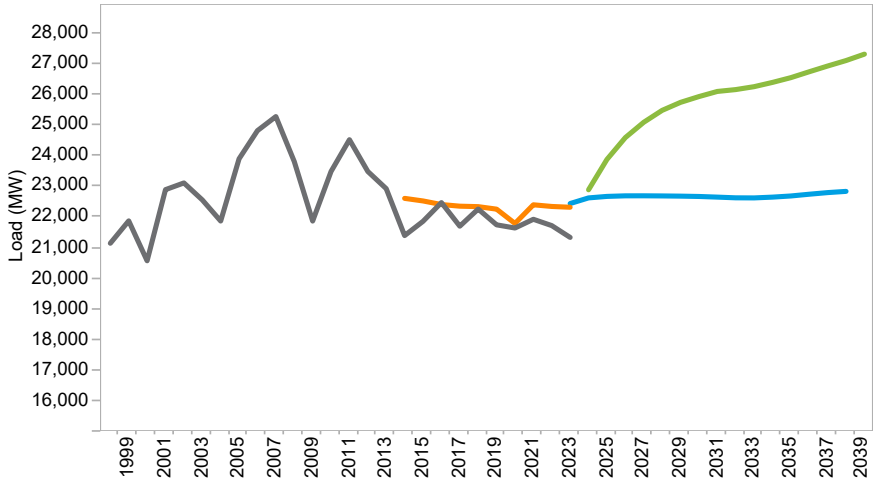


Scranton--Wilkes-Barre--Hazleton, PA

Peak WN peak Forecast 2023 Forecast 2024

American Electric Power (AEP)

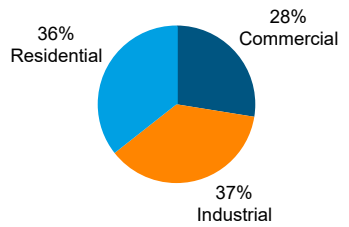
Summer Peak



Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*73.2*
Avg Summer Max Temp	*92.4*
Avg Winter Daily Temp	*33.2*
Avg Winter Min Temp	*2.6*

RCI Makeup



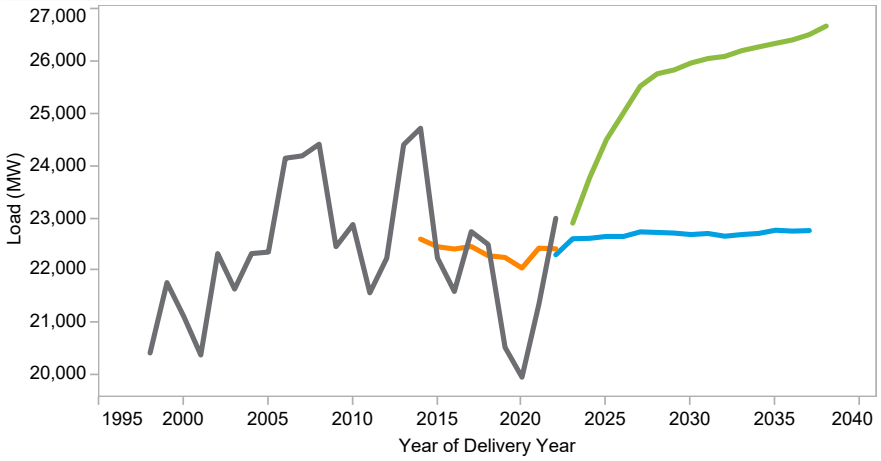
Zonal 10/15 Year Load Growth

SUMMER	1.4%	1.2%
WINTER	1.4%	1.0%

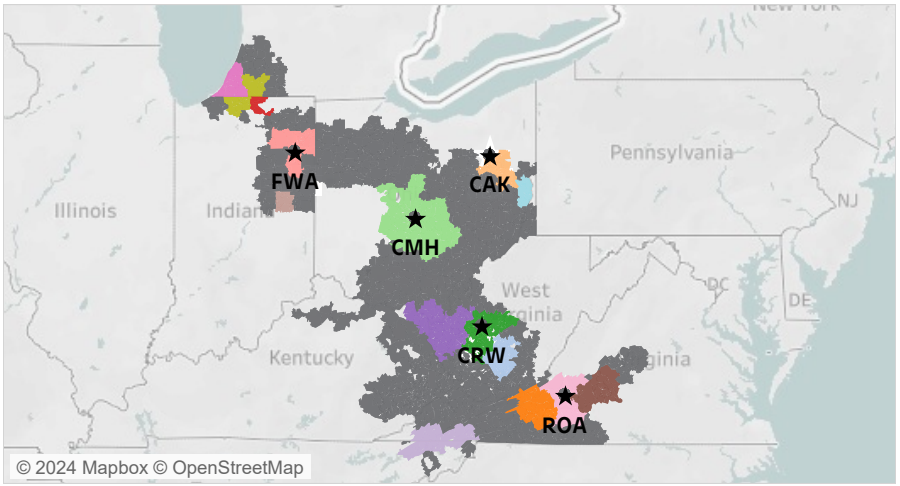
LDAs

PJM RTO PJM WESTERN

Winter Peak



Metropolitan Statistical Areas and Weather Stations

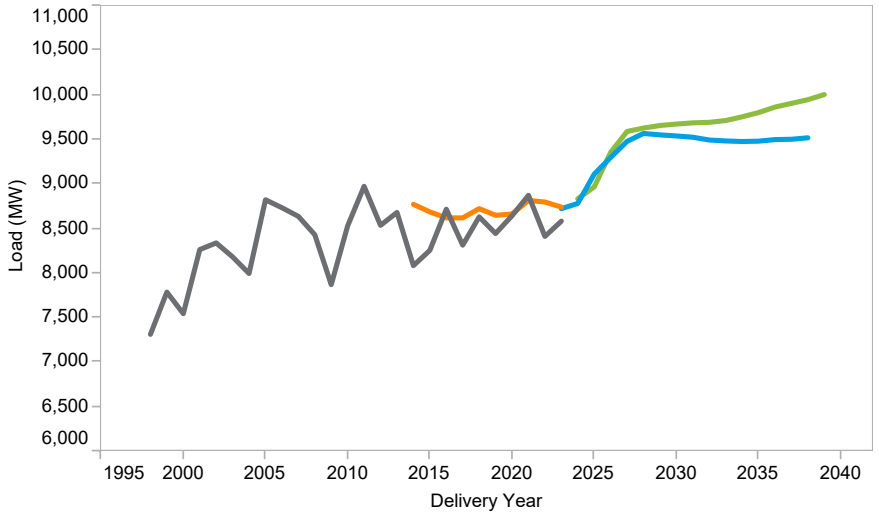


Peak
WN peak
Forecast 2023
Forecast 2024

AEP - Non-Metro
Beckley, WV
Blacksburg-Christiansburg-Radford, VA
Canton-Massillon, OH
Charleston, WV
Columbus, OH
Elkhart-Goshen, IN
Fort Wayne, IN
Huntington-Ashland, WV-KY-OH
Kingsport-Bristol-Bristol, TN-VA
Lynchburg, VA
Muncie, IN
Niles-Benton Harbor, MI
Roanoke, VA
South Bend-Mishawaka, IN-MI
Weirton-Steubenville, WV-OH

Allegheny Power Systems (APS)

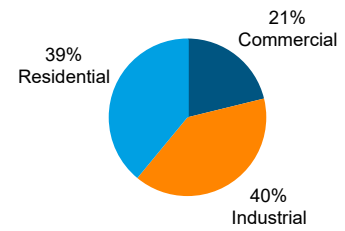
Summer Peak



Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*72.8*
Avg Summer Max Temp	*92.5*
Avg Winter Daily Temp	*32.9*
Avg Winter Min Temp	*2.2*

RCI Makeup



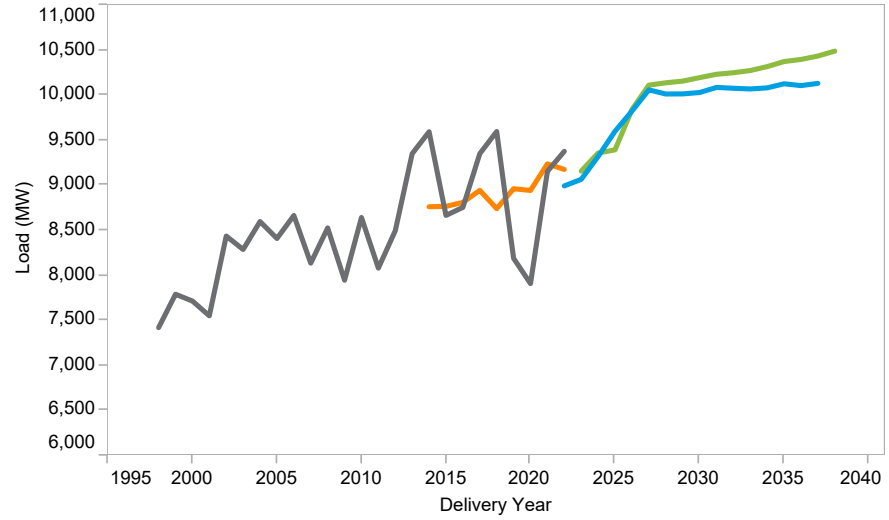
Zonal 10/15 Year Load Growth

SUMMER	1.0%	0.8%
WINTER	1.2%	0.9%

LDAs

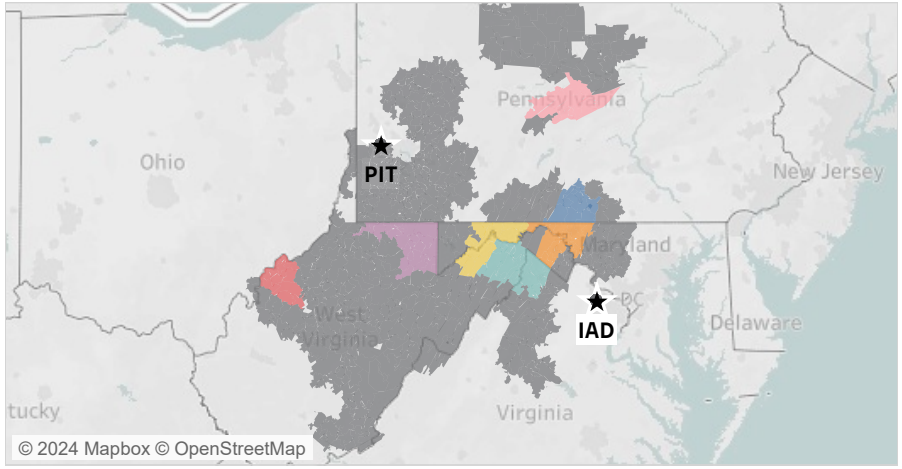
PJM RTO PJM WESTERN

Winter Peak



Peak WN peak Forecast 2023 Forecast 2024

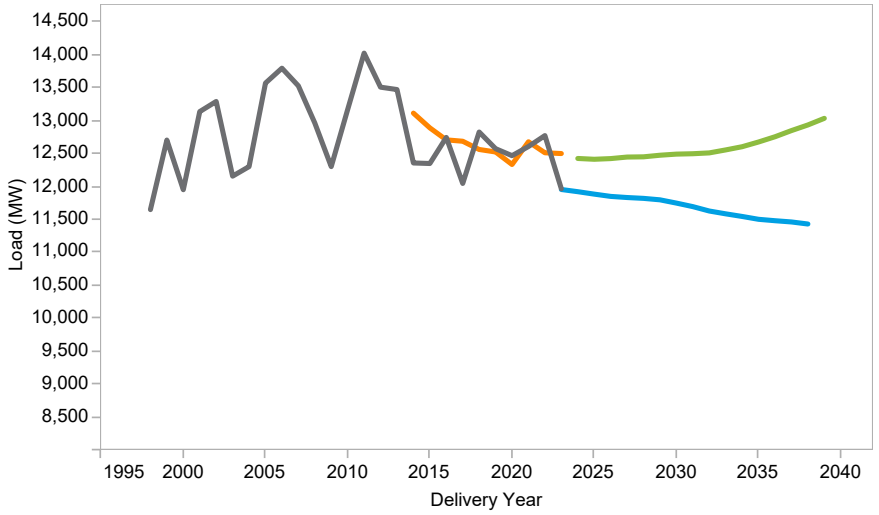
Metropolitan Statistical Areas and Weather Stations



- APS - Non-metro
- Chambersburg-Waynesboro, PA
- Cumberland, MD-WV
- Hagerstown-Martinsburg, MD-WV
- Morgantown, WV
- Parkersburg-Vienna, WV
- State College, PA
- Winchester, VA-WV

American Transmission Systems, Inc. (ATSI)

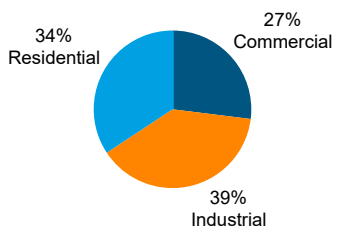
Summer Peak



Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*71.7*
Avg Summer Max Temp	*92.0*
Avg Winter Daily Temp	*29.9*
Avg Winter Min Temp	*-1.4*

RCI Makeup



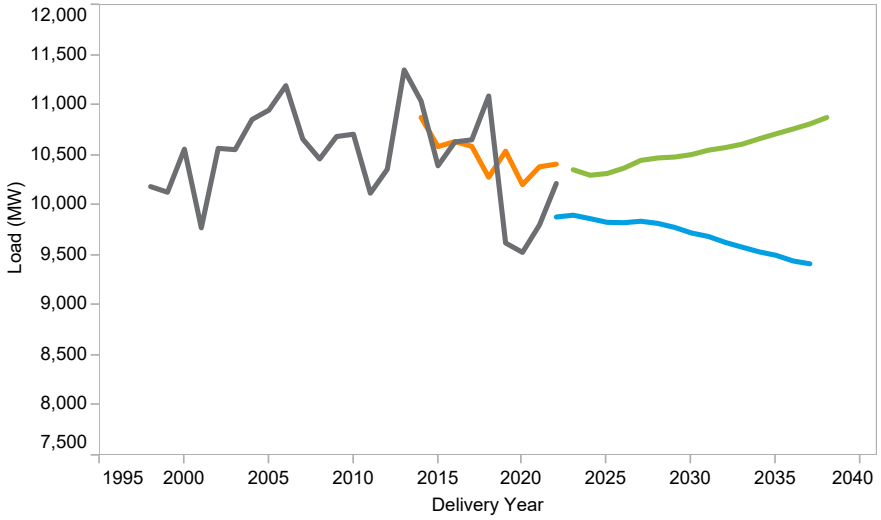
Zonal 10/15 Year Load Growth

SUMMER	0.1%	0.3%
WINTER	0.2%	0.3%

LDAs

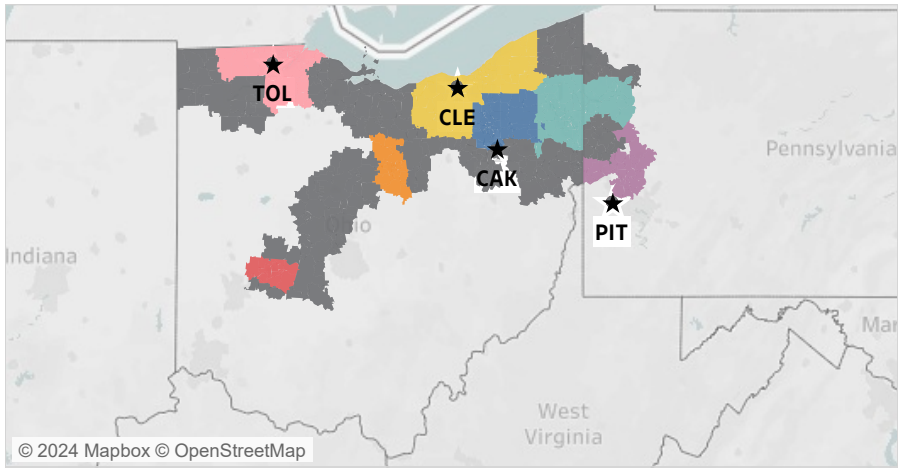
PJM RTO PJM WESTERN

Winter Peak



Peak WN peak Forecast 2023 Forecast 2024

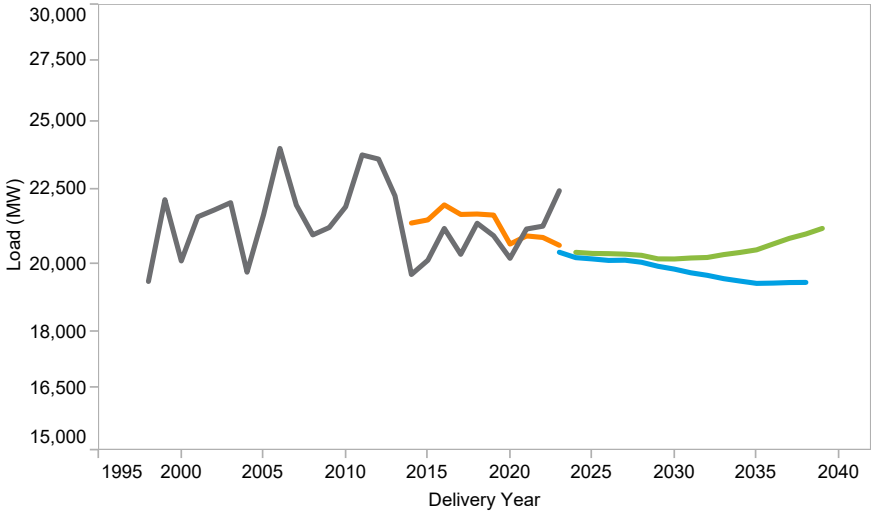
Metropolitan Statistical Areas and Weather Stations



Akron, OH
ATSI - Non-Metro
Cleveland-Elyria, OH
Mansfield, OH
Pittsburgh, PA
Springfield, OH
Toledo, OH
Youngstown-Warren-Boardman, OH-PA

Commonweath Edison (COMED)

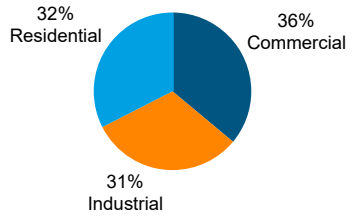
Summer Peak



Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*73.0*
Avg Summer Max Temp	*95.4*
Avg Winter Daily Temp	*27.6*
Avg Winter Min Temp	*-7.4*

RCI Makeup



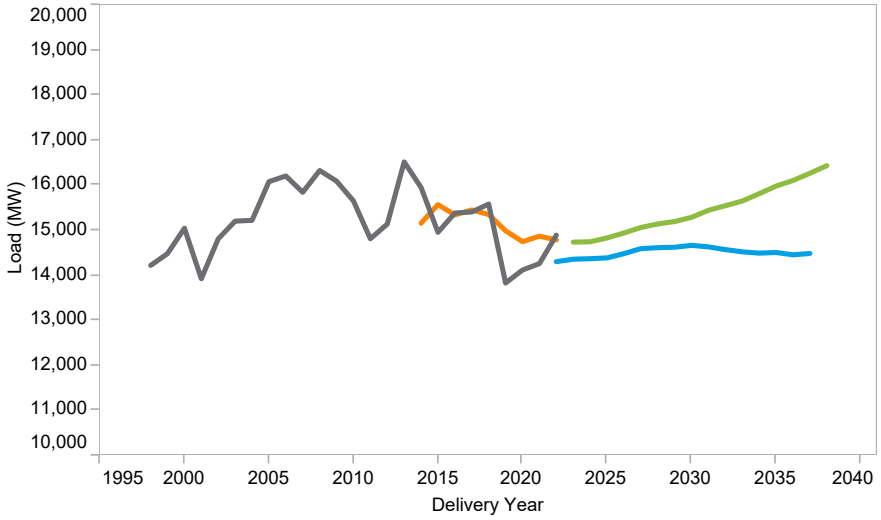
Zonal 10/15 Year Load Growth

SUMMER	0.0%	0.2%
WINTER	0.6%	0.7%

LDAs

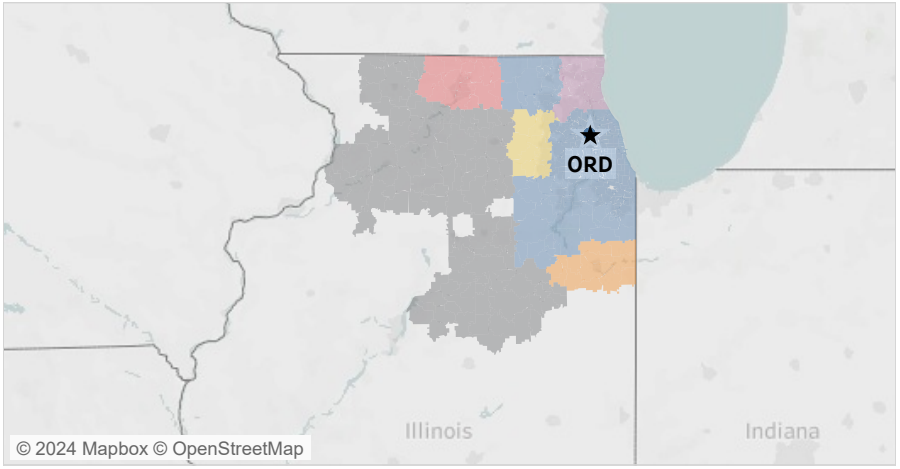
PJM RTO PJM WESTERN

Winter Peak



Peak WN peak Forecast 2023 Forecast 2024

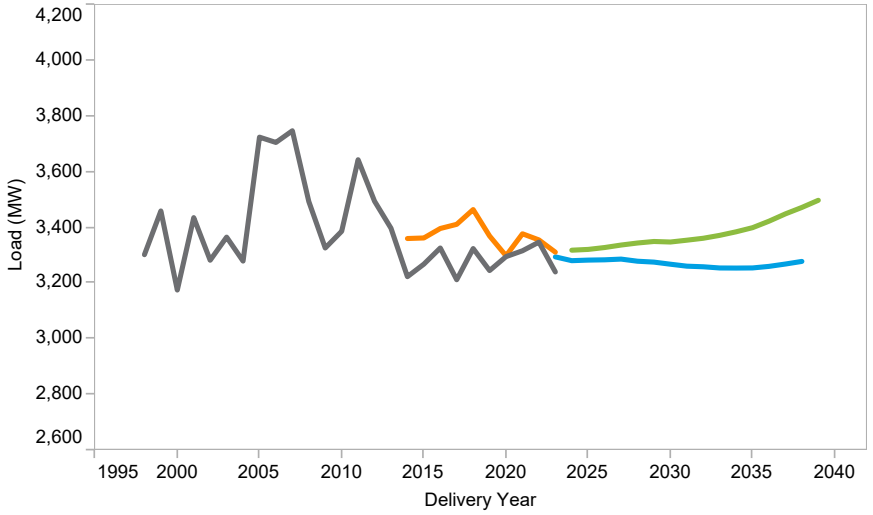
Metropolitan Statistical Areas and Weather Stations



Chicago-Naperville-Arlington Heights, IL
Chicago-Naperville-Elgin, IL-IN-WI
COMED - Non-Metro
Kankakee, IL
Lake County-Kenosha County, IL-WI
Rockford, IL

Dayton Power and Light (DAYTON)

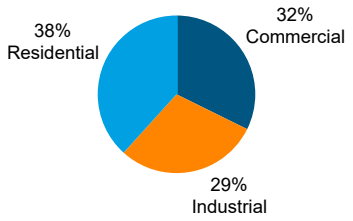
Summer Peak



Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*73.2*
Avg Summer Max Temp	*93.1*
Avg Winter Daily Temp	*31.0*
Avg Winter Min Temp	*-3.4*

RCI Makeup



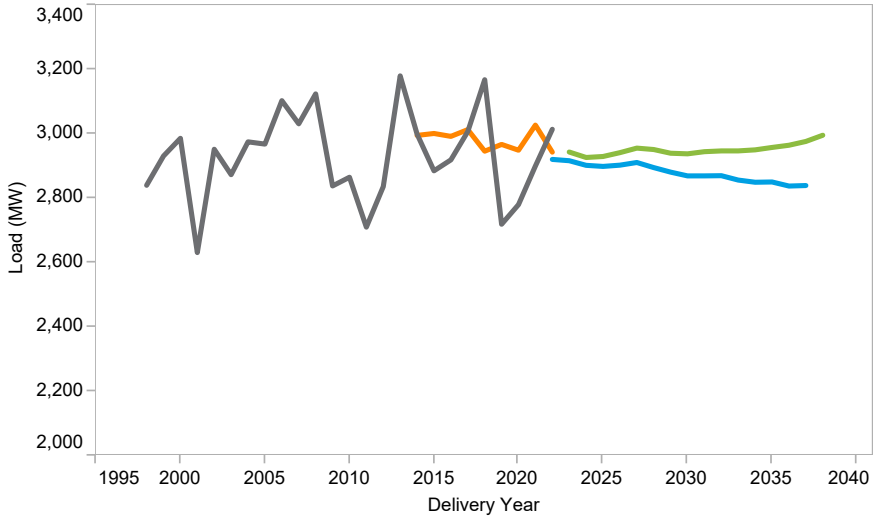
Zonal 10/15 Year Load Growth

SUMMER	0.2%	0.4%
WINTER	0.0%	0.1%

LDAs

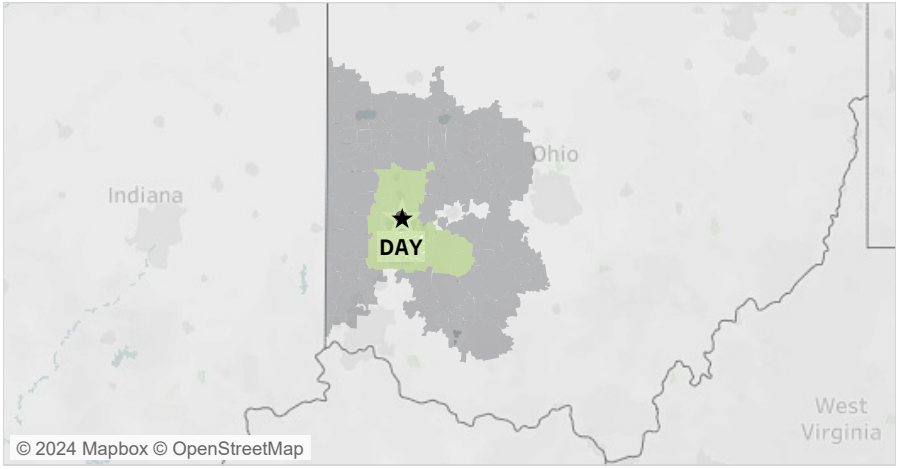
PJM RTO PJM WESTERN

Winter Peak



Peak WN peak Forecast 2023 Forecast 2024

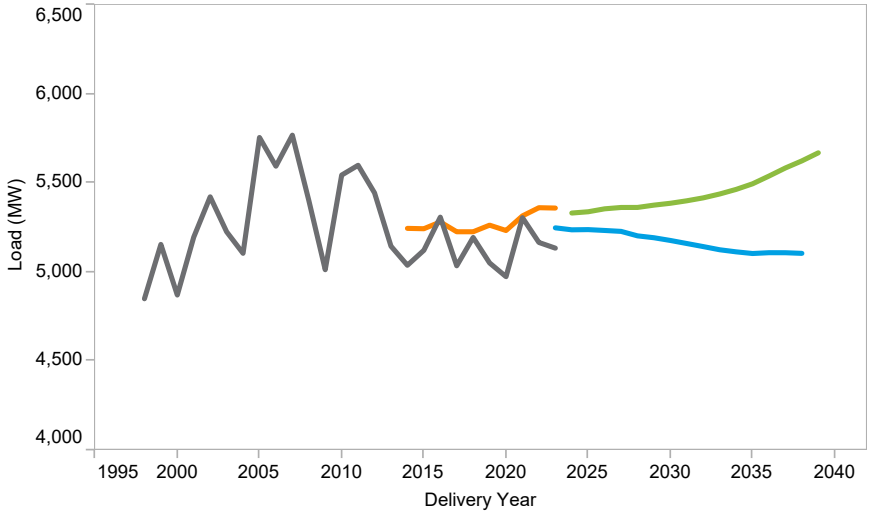
Metropolitan Statistical Areas and Weather Stations



DAY - Non-Metro
Dayton, OH

Duke Energy Ohio and Kentucky (DEOK)

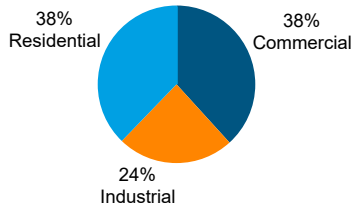
Summer Peak



Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*74.4*
Avg Summer Max Temp	*94.0*
Avg Winter Daily Temp	*33.9*
Avg Winter Min Temp	*-1.7*

RCI Makeup



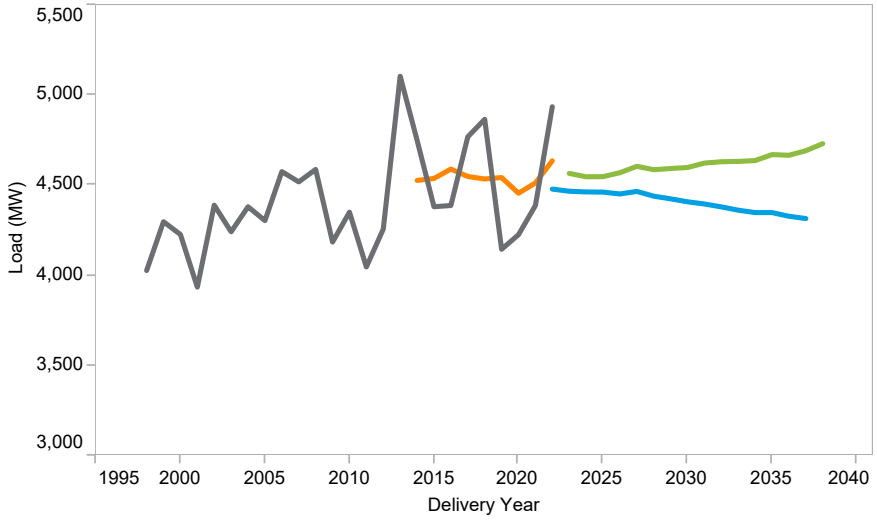
Zonal 10/15 Year Load Growth

SUMMER	0.2%	0.4%
WINTER	0.1%	0.2%

LDAs

PJM RTO PJM WESTERN

Winter Peak



Peak WN peak Forecast 2023 Forecast 2024

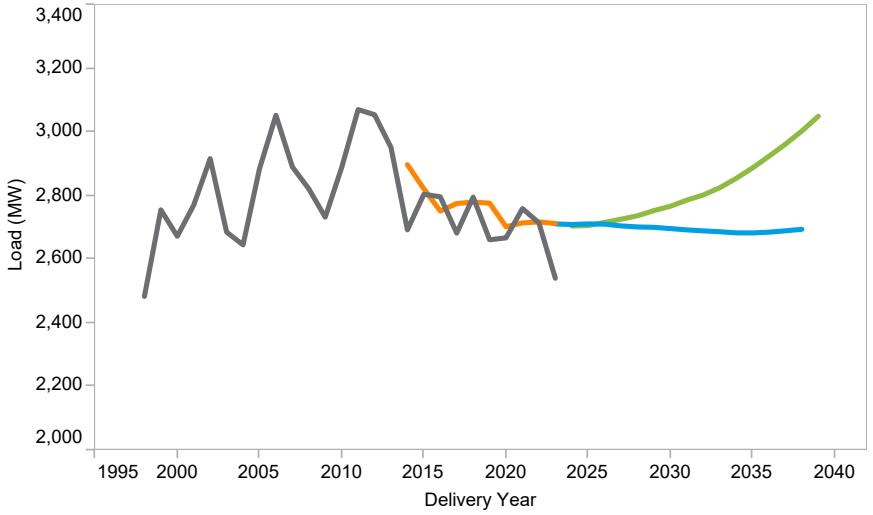
Metropolitan Statistical Areas and Weather Stations



Cincinnati, OH-KY-IN
DEOK - Non-Metro

Duquesne Light Company (DLCO)

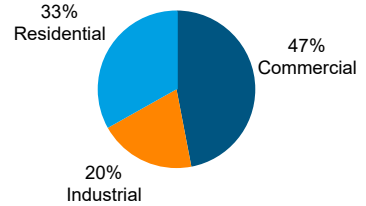
Summer Peak



Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*71.7*
Avg Summer Max Temp	*91.7*
Avg Winter Daily Temp	*31.4*
Avg Winter Min Temp	*-1.0*

RCI Makeup



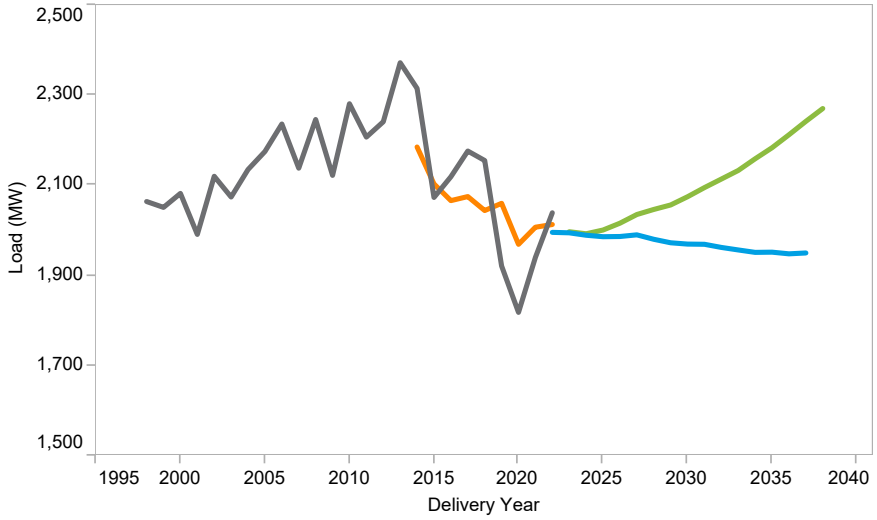
Zonal 10/15 Year Load Growth

SUMMER	0.5%	0.8%
WINTER	0.7%	0.9%

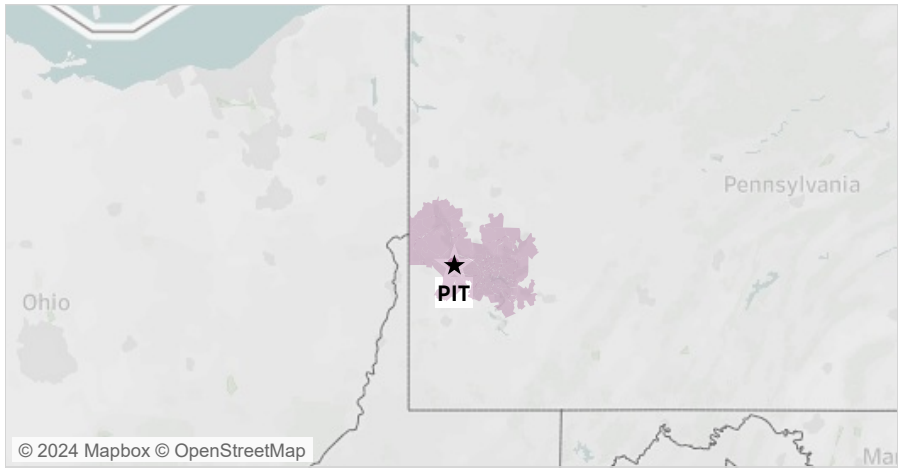
LDAs

PJM RTO PJM WESTERN

Winter Peak



Metropolitan Statistical Areas and Weather Stations

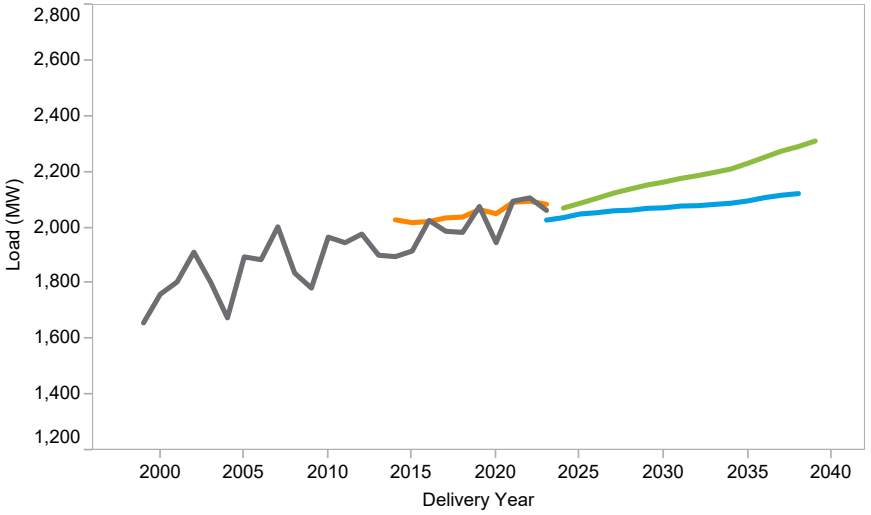


Pittsburgh, PA

Peak WN peak Forecast 2023 Forecast 2024

East Kentucky Power Cooperative (EKPC)

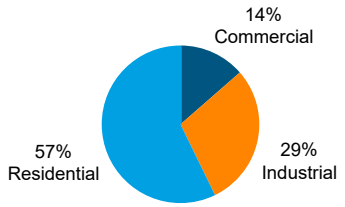
Summer Peak



Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*75.5*
Avg Summer Max Temp	*94.3*
Avg Winter Daily Temp	*35.9*
Avg Winter Min Temp	*1.9*

RCI Makeup



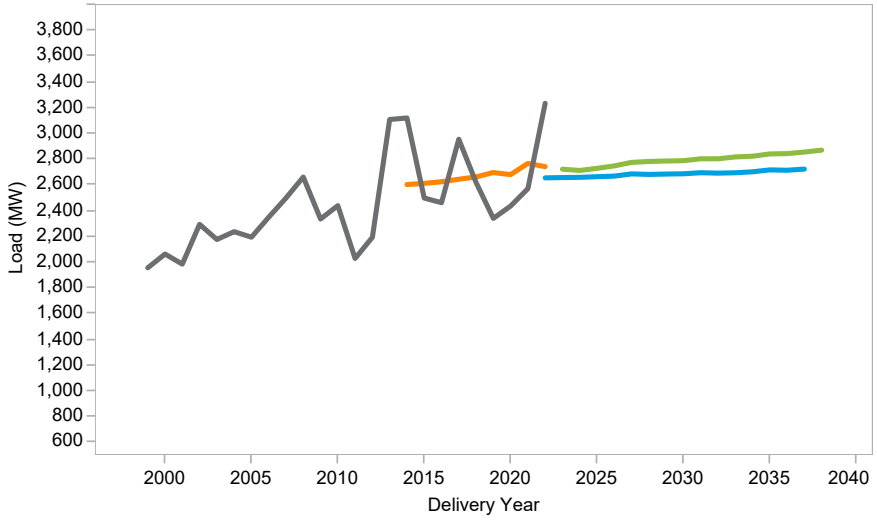
Zonal 10/15 Year Load Growth

SUMMER	0.7%	0.7%
WINTER	0.3%	0.4%

LDAs

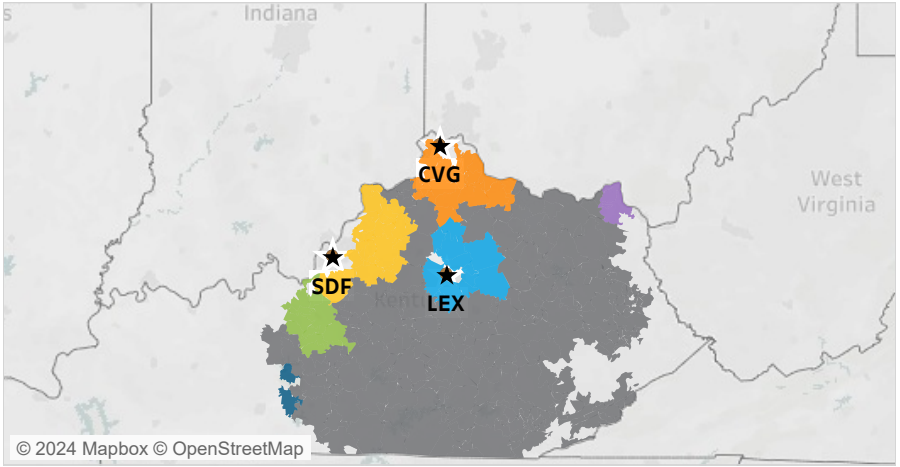
PJM RTO PJM WESTERN

Winter Peak



Peak WN peak Forecast 2023 Forecast 2024

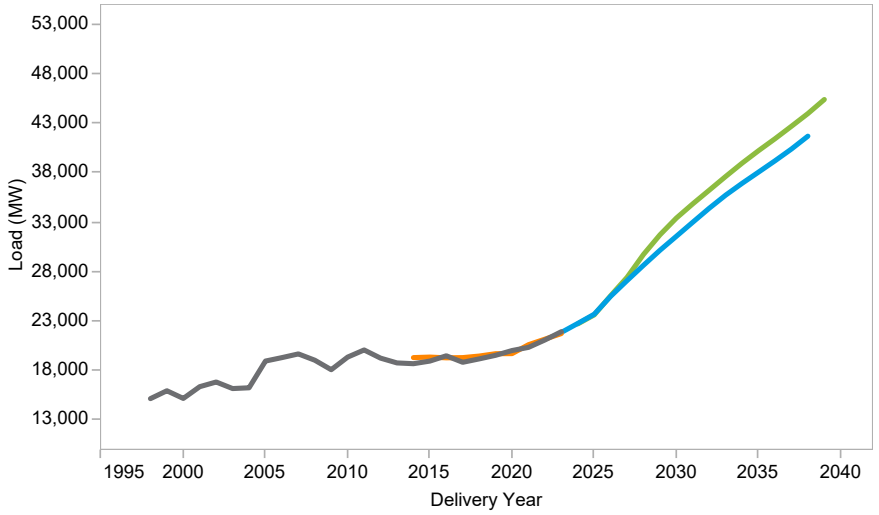
Metropolitan Statistical Areas and Weather Stations



Bowling Green, KY
Cincinnati, OH-KY-IN
EKPC - Non-Metro
Elizabethtown-Fort Knox, KY
Huntington-Ashland, WV-KY-OH
Lexington-Fayette, KY
Louisville/Jefferson County, KY-IN

Dominion (DOM)

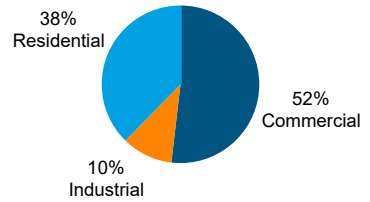
Summer Peak



Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*76.9*
Avg Summer Max Temp	*96.9*
Avg Winter Daily Temp	*40.3*
Avg Winter Min Temp	*12.3*

RCI Makeup



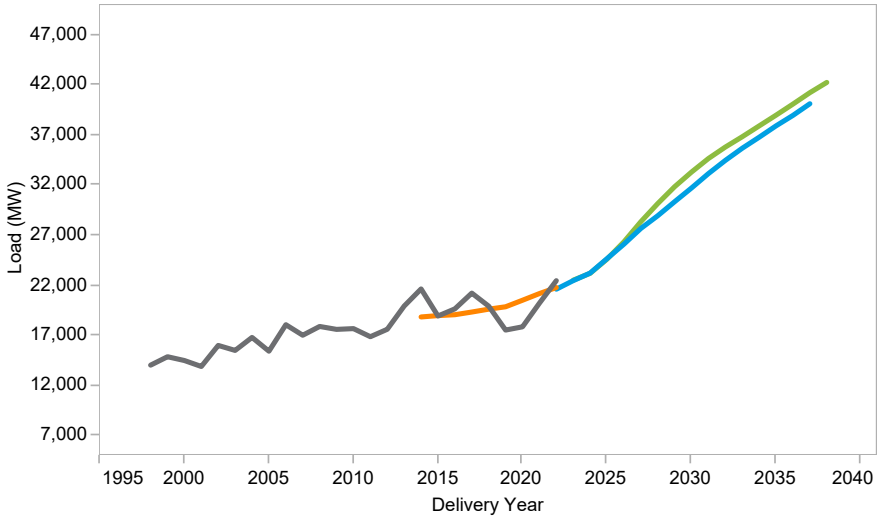
Zonal 10/15 Year Load Growth

SUMMER	5.5%	4.7%
WINTER	5.0%	4.3%

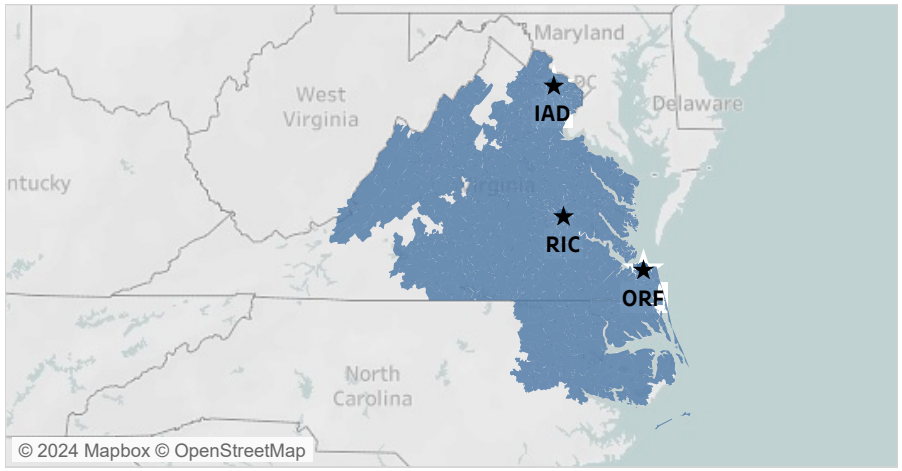
LDAs

PJM RTO

Winter Peak



Metropolitan Statistical Areas and Weather Stations



Virginia Commonwealth Economics

Peak WN peak Forecast 2023 Forecast 2024

Table A-1

PJM MID-ATLANTIC REGION
SUMMER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST
TO THE JANUARY 2023 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	2024		2029		2034	
	MW	**%**	**MW**	**%**	**MW**	**%**
AE	67	2.7%	147	6.0%	308	12.8%
BGE	63	1.0%	393	6.3%	926	15.4%
DPL	104	2.7%	181	4.8%	397	10.9%
JCPL	20	0.3%	320	5.4%	940	16.2%
METED	(5)	-0.2%	240	7.8%	597	19.1%
PECO	59	0.7%	191	2.2%	443	5.2%
PENLC	9	0.3%	82	2.9%	190	6.8%
PEPCO	(111)	-1.8%	(8)	-0.1%	242	3.9%
PL	(55)	-0.8%	23	0.3%	146	2.0%
PS	244	2.5%	881	9.1%	1,711	18.0%
RECO	(5)	-1.2%	(10)	-2.4%	6	1.4%
UGI	3	1.5%	7	3.6%	15	8.0%
PJM MID-ATLANTIC	383	0.7%	2,257	4.1%	5,890	10.9%
FE-EAST	50	0.4%	597	5.2%	1,703	14.9%
PLGRP	(56)	-0.8%	25	0.3%	151	2.0%

Table A-1

PJM WESTERN REGION, PJM SOUTHERN REGION AND PJM RTO
SUMMER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST
TO THE JANUARY 2023 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	2024		2029		2034	
	MW	**%**	**MW**	**%**	**MW**	**%**
AEP	265	1.2%	3,062	13.5%	3,745	16.5%
APS	52	0.6%	106	1.1%	277	2.9%
ATSI	504	4.2%	678	5.7%	1,059	9.2%
COMED	168	0.8%	231	1.2%	889	4.6%
DAYTON	38	1.2%	74	2.3%	130	4.0%
DEOK	94	1.8%	183	3.5%	351	6.9%
DLCO	(5)	-0.2%	53	2.0%	171	6.4%
EKPC	34	1.7%	84	4.1%	123	5.9%
OVEC	(5)	-5.3%	(5)	-5.3%	(5)	-5.3%
PJM WESTERN	1,129	1.5%	4,396	5.8%	6,655	8.9%
DOM	(47)	-0.2%	1,560	5.2%	2,039	5.5%
PJM RTO	1,510	1.0%	8,758	5.6%	14,727	9.1%

Table A-2

PJM MID-ATLANTIC REGION
WINTER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST
TO THE JANUARY 2023 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	23/24		28/29		33/34	
	MW	**%**	**MW**	**%**	**MW**	**%**
AE	52	3.3%	297	18.8%	608	39.2%
BGE	80	1.4%	236	4.1%	646	11.4%
DPL	68	1.9%	124	3.4%	231	6.3%
JCPL	65	1.7%	1,041	27.0%	2,189	56.8%
METED	22	0.8%	244	8.9%	599	21.7%
PECO	85	1.3%	217	3.3%	446	6.8%
PENLC	5	0.2%	44	1.6%	132	4.8%
PEPCO	(49)	-0.9%	9	0.2%	203	3.7%
PL	29	0.4%	24	0.3%	74	1.0%
PS	283	4.3%	1,901	29.3%	3,542	55.7%
RECO	5	2.3%	22	9.0%	59	23.7%
UGI	3	1.5%	6	3.1%	13	6.8%
PJM MID-ATLANTIC	798	1.7%	4,456	9.7%	9,196	20.2%
FE-EAST	101	1.1%	1,340	14.4%	2,913	31.4%
PLGRP	37	0.5%	31	0.4%	87	1.2%

Table A-2

PJM WESTERN REGION, PJM SOUTHERN REGION AND PJM RTO
WINTER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST
TO THE JANUARY 2023 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	23/24		28/29		33/34	
	MW	**%**	**MW**	**%**	**MW**	**%**
AEP	298	1.3%	3,033	13.3%	3,515	15.5%
APS	92	1.0%	124	1.2%	204	2.0%
ATSI	455	4.6%	653	6.6%	1,029	10.7%
COMED	379	2.6%	526	3.6%	1,128	7.8%
DAYTON	27	0.9%	56	1.9%	91	3.2%
DEOK	99	2.2%	147	3.3%	270	6.2%
DLCO	2	0.1%	66	3.3%	176	9.0%
EKPC	65	2.4%	101	3.8%	123	4.6%
OVEC	0	0.0%	0	0.0%	0	0.0%
PJM WESTERN	1,418	2.1%	4,591	6.8%	6,688	10.0%
DOM	45	0.2%	1,216	4.2%	1,149	3.2%
PJM RTO	1,992	1.5%	9,929	7.1%	17,091	11.7%

Table B-1

SUMMER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION 2024 - 2034

	METERED 2023	UNRESTRICTED 2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Annual Growth Rate (10 yr)
AE	2,629	2,629	2,593	2,599	2,602	2,601	2,603	2,614	2,623	2,641	2,661	2,685	2,715	0.5%
				0.2%	0.1%	-0.0%	0.1%	0.4%	0.3%	0.7%	0.8%	0.9%	1.1%	
BGE	6,406	6,406	6,491	6,507	6,523	6,554	6,592	6,636	6,676	6,719	6,781	6,849	6,931	0.7%
				0.2%	0.2%	0.5%	0.6%	0.7%	0.6%	0.6%	0.9%	1.0%	1.2%	
DPL	4,078	4,094	3,945	3,926	3,913	3,912	3,916	3,928	3,941	3,962	3,981	4,010	4,050	0.3%
				-0.5%	-0.3%	-0.0%	0.1%	0.3%	0.3%	0.5%	0.5%	0.7%	1.0%	
JCPL	5,732	5,732	6,052	6,085	6,099	6,128	6,175	6,252	6,315	6,392	6,490	6,609	6,750	1.1%
				0.5%	0.2%	0.5%	0.8%	1.2%	1.0%	1.2%	1.5%	1.8%	2.1%	
METED	2,891	2,891	3,036	3,077	3,141	3,205	3,256	3,323	3,383	3,454	3,538	3,620	3,715	2.0%
				1.4%	2.1%	2.0%	1.6%	2.1%	1.8%	2.1%	2.4%	2.3%	2.6%	
PECO	8,163	8,163	8,581	8,599	8,640	8,679	8,716	8,754	8,796	8,852	8,907	8,972	9,031	0.5%
				0.2%	0.5%	0.5%	0.4%	0.4%	0.5%	0.6%	0.6%	0.7%	0.7%	
PENLC	2,764	2,764	2,867	2,872	2,885	2,892	2,897	2,903	2,913	2,930	2,940	2,955	2,970	0.4%
				0.2%	0.5%	0.2%	0.2%	0.2%	0.3%	0.6%	0.3%	0.5%	0.5%	
PEPCO	5,872	5,872	6,053	6,082	6,104	6,126	6,164	6,206	6,250	6,297	6,337	6,388	6,440	0.6%
				0.5%	0.4%	0.4%	0.6%	0.7%	0.7%	0.8%	0.6%	0.8%	0.8%	
PL	6,899	6,915	7,126	7,156	7,196	7,218	7,227	7,241	7,266	7,306	7,331	7,357	7,382	0.4%
				0.4%	0.6%	0.3%	0.1%	0.2%	0.3%	0.6%	0.3%	0.4%	0.3%	
PS	9,562	9,562	10,068	10,143	10,224	10,296	10,383	10,520	10,638	10,740	10,859	11,013	11,193	1.1%
				0.7%	0.8%	0.7%	0.8%	1.3%	1.1%	1.0%	1.1%	1.4%	1.6%	
RECO	385	385	410	410	411	409	407	409	409	410	413	417	421	0.3%
				0.0%	0.2%	-0.5%	-0.5%	0.5%	0.0%	0.2%	0.7%	1.0%	1.0%	
UGI	195	195	197	198	198	198	198	199	199	200	201	202	203	0.3%
				0.5%	0.0%	0.0%	0.0%	0.5%	0.0%	0.5%	0.5%	0.5%	0.5%	
DIVERSITY - MID-ATLANTIC(-)			1,586	1,636	1,603	1,729	1,830	1,990	2,009	1,993	1,913	1,975	1,896	
PJM MID-ATLANTIC	54,507	54,540	55,833	56,018	56,333	56,489	56,704	56,995	57,400	57,910	58,526	59,102	59,905	0.7%
				0.3%	0.6%	0.3%	0.4%	0.5%	0.7%	0.9%	1.1%	1.0%	1.4%	
FE-EAST	11,191	11,191	11,723	11,791	11,882	11,973	12,050	12,187	12,305	12,467	12,682	12,895	13,151	1.2%
				0.6%	0.8%	0.8%	0.6%	1.1%	1.0%	1.3%	1.7%	1.7%	2.0%	
PLGRP	7,093	7,109	7,323	7,354	7,394	7,414	7,420	7,437	7,462	7,506	7,530	7,551	7,578	0.3%
				0.4%	0.5%	0.3%	0.1%	0.2%	0.3%	0.6%	0.3%	0.3%	0.4%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2024).
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 2035 - 2039

	2035	2036	2037	2038	2039	Annual Growth Rate (15 yr)
AE	2,755	2,793	2,839	2,873	2,916	0.8%
	1.5%	1.4%	1.6%	1.2%	1.5%	
BGE	7,036	7,139	7,258	7,364	7,495	1.0%
	1.5%	1.5%	1.7%	1.5%	1.8%	
DPL	4,091	4,146	4,201	4,238	4,292	0.6%
	1.0%	1.3%	1.3%	0.9%	1.3%	
JCPL	6,902	7,058	7,224	7,367	7,547	1.5%
	2.3%	2.3%	2.4%	2.0%	2.4%	
METED	3,824	3,942	4,077	4,200	4,343	2.4%
	2.9%	3.1%	3.4%	3.0%	3.4%	
PECO	9,113	9,233	9,326	9,409	9,519	0.7%
	0.9%	1.3%	1.0%	0.9%	1.2%	
PENLC	2,996	3,032	3,072	3,102	3,137	0.6%
	0.9%	1.2%	1.3%	1.0%	1.1%	
PEPCO	6,503	6,591	6,687	6,772	6,870	0.8%
	1.0%	1.4%	1.5%	1.3%	1.4%	
PL	7,427	7,497	7,567	7,621	7,687	0.5%
	0.6%	0.9%	0.9%	0.7%	0.9%	
PS	11,365	11,570	11,787	11,987	12,218	1.3%
	1.5%	1.8%	1.9%	1.7%	1.9%	
RECO	426	431	437	443	449	0.6%
	1.2%	1.2%	1.4%	1.4%	1.4%	
UGI	204	206	209	210	213	0.5%
	0.5%	1.0%	1.5%	0.5%	1.4%	
DIVERSITY - MID-ATLANTIC(-)	1,918	1,970	1,785	1,802	1,864	
PJM MID-ATLANTIC	60,724	61,668	62,899	63,784	64,822	1.0%
	1.4%	1.6%	2.0%	1.4%	1.6%	
FE-EAST	13,432	13,738	14,074	14,381	14,746	1.5%
	2.1%	2.3%	2.4%	2.2%	2.5%	
PLGRP	7,624	7,701	7,772	7,827	7,897	0.5%
	0.6%	1.0%	0.9%	0.7%	0.9%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2024).
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 2024 - 2034

	METERED 2023	UNRESTRICTED 2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Annual Growth Rate (10 yr)
AEP	21,348	21,348	22,902	23,893	24,607	25,106	25,495	25,757	25,945	26,113	26,174	26,269	26,408	1.4%
				4.3%	3.0%	2.0%	1.5%	1.0%	0.7%	0.6%	0.2%	0.4%	0.5%	
APS	8,584	8,585	8,835	8,968	9,356	9,591	9,629	9,658	9,674	9,687	9,693	9,713	9,755	1.0%
				1.5%	4.3%	2.5%	0.4%	0.3%	0.2%	0.1%	0.1%	0.2%	0.4%	
ATSI	11,963	11,974	12,433	12,421	12,432	12,455	12,458	12,483	12,500	12,505	12,518	12,563	12,612	0.1%
				-0.1%	0.1%	0.2%	0.0%	0.2%	0.1%	0.0%	0.1%	0.4%	0.4%	
COMED	22,468	22,468	20,414	20,380	20,372	20,356	20,320	20,208	20,204	20,236	20,252	20,343	20,411	(0.0%)
				-0.2%	-0.0%	-0.1%	-0.2%	-0.6%	-0.0%	0.2%	0.1%	0.4%	0.3%	
DAYTON	3,241	3,241	3,319	3,322	3,329	3,338	3,345	3,350	3,348	3,355	3,362	3,372	3,385	0.2%
				0.1%	0.2%	0.3%	0.2%	0.1%	-0.1%	0.2%	0.2%	0.3%	0.4%	
DEOK	5,135	5,135	5,332	5,339	5,356	5,363	5,363	5,376	5,387	5,401	5,417	5,439	5,465	0.2%
				0.1%	0.3%	0.1%	0.0%	0.2%	0.2%	0.3%	0.3%	0.4%	0.5%	
DLCO	2,535	2,541	2,705	2,707	2,716	2,727	2,737	2,754	2,767	2,787	2,803	2,826	2,855	0.5%
				0.1%	0.3%	0.4%	0.4%	0.6%	0.5%	0.7%	0.6%	0.8%	1.0%	
EKPC	2,063	2,063	2,070	2,088	2,105	2,124	2,139	2,153	2,164	2,177	2,187	2,199	2,211	0.7%
				0.9%	0.8%	0.9%	0.7%	0.7%	0.5%	0.6%	0.5%	0.5%	0.5%	
OVEC	82	82	90	90	90	90	90	90	90	90	90	90	90	0.0%
				0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
DIVERSITY - WESTERN(-)			1,571	1,612	1,552	1,516	1,523	1,665	1,719	1,858	1,776	1,810	1,801	
PJM WESTERN	73,321	73,330	76,529	77,596	78,811	79,634	80,053	80,164	80,360	80,493	80,720	81,004	81,391	0.6%
				1.4%	1.6%	1.0%	0.5%	0.1%	0.2%	0.2%	0.3%	0.4%	0.5%	
DOM	21,993	21,993	22,781	23,691	25,627	27,487	29,800	31,776	33,472	34,911	36,288	37,673	39,019	5.5%
				4.0%	8.2%	7.3%	8.4%	6.6%	5.3%	4.3%	3.9%	3.8%	3.6%	
DIVERSITY - TOTAL(-)			7,053	7,060	7,123	6,996	6,938	6,909	7,087	7,157	7,114	7,198	7,190	
PJM RTO	146,745	146,799	151,247	153,493	156,803	159,859	162,972	165,681	167,873	170,008	172,109	174,366	176,822	1.6%
				1.5%	2.2%	1.9%	1.9%	1.7%	1.3%	1.3%	1.2%	1.3%	1.4%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2024).
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 2035 - 2039

	2035	2036	2037	2038	2039	Annual Growth Rate (15 yr)
AEP	26,564	26,756	26,944	27,122	27,331	1.2%
	0.6%	0.7%	0.7%	0.7%	0.8%	
APS	9,803	9,865	9,906	9,947	10,005	0.8%
	0.5%	0.6%	0.4%	0.4%	0.6%	
ATSI	12,684	12,763	12,857	12,942	13,043	0.3%
	0.6%	0.6%	0.7%	0.7%	0.8%	
COMED	20,494	20,679	20,864	21,005	21,188	0.2%
	0.4%	0.9%	0.9%	0.7%	0.9%	
DAYTON	3,400	3,423	3,450	3,473	3,498	0.4%
	0.4%	0.7%	0.8%	0.7%	0.7%	
DEOK	5,496	5,540	5,585	5,625	5,670	0.4%
	0.6%	0.8%	0.8%	0.7%	0.8%	
DLCO	2,888	2,924	2,962	3,004	3,050	0.8%
	1.2%	1.2%	1.3%	1.4%	1.5%	
EKPC	2,231	2,253	2,275	2,291	2,311	0.7%
	0.9%	1.0%	1.0%	0.7%	0.9%	
OVEC	90	90	90	90	90	0.0%
	0.0%	0.0%	0.0%	0.0%	0.0%	
DIVERSITY - WESTERN(-)	1,740	1,853	1,862	1,872	1,842	
PJM WESTERN	81,910	82,440	83,071	83,627	84,344	0.7%
	0.6%	0.6%	0.8%	0.7%	0.9%	
DOM	40,279	41,482	42,742	44,023	45,445	4.7%
	3.2%	3.0%	3.0%	3.0%	3.2%	
DIVERSITY - TOTAL(-)	6,949	6,926	7,232	7,356	7,565	
PJM RTO	179,622	182,487	185,127	187,752	190,752	1.6%
	1.6%	1.6%	1.4%	1.4%	1.6%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2024).
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 2023/24 - 2033/34

	METERED 22/23	UNRESTRICTED 22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32	32/33	33/34	Annual Growth Rate (10 yr)
AE	1,559	1,566	1,637	1,673	1,721	1,774	1,835	1,876	1,928	1,988	2,053	2,105	2,161	2.8%
				2.2%	2.9%	3.1%	3.4%	2.2%	2.8%	3.1%	3.3%	2.5%	2.7%	
BGE	5,912	5,968	5,827	5,836	5,855	5,899	5,947	5,973	6,020	6,092	6,162	6,242	6,313	0.8%
				0.2%	0.3%	0.8%	0.8%	0.4%	0.8%	1.2%	1.1%	1.3%	1.1%	
DPL	3,659	3,705	3,700	3,705	3,730	3,756	3,793	3,793	3,812	3,833	3,872	3,894	3,915	0.6%
				0.1%	0.7%	0.7%	1.0%	0.0%	0.5%	0.6%	1.0%	0.6%	0.5%	
JCPL	3,497	3,517	3,817	3,989	4,208	4,439	4,678	4,892	5,115	5,354	5,610	5,819	6,040	4.7%
				4.5%	5.5%	5.5%	5.4%	4.6%	4.6%	4.7%	4.8%	3.7%	3.8%	
METED	2,534	2,535	2,740	2,752	2,799	2,859	2,946	2,987	3,054	3,122	3,210	3,281	3,365	2.1%
				0.4%	1.7%	2.1%	3.0%	1.4%	2.2%	2.2%	2.8%	2.2%	2.6%	
PECO	6,346	6,416	6,597	6,583	6,616	6,664	6,729	6,733	6,768	6,812	6,878	6,916	6,967	0.5%
				-0.2%	0.5%	0.7%	1.0%	0.1%	0.5%	0.7%	1.0%	0.6%	0.7%	
PENLC	2,722	2,726	2,829	2,811	2,815	2,820	2,836	2,828	2,826	2,837	2,862	2,859	2,869	0.1%
				-0.6%	0.1%	0.2%	0.6%	-0.3%	-0.1%	0.4%	0.9%	-0.1%	0.3%	
PEPCO	5,081	5,099	5,359	5,365	5,397	5,434	5,473	5,498	5,542	5,595	5,657	5,697	5,745	0.7%
				0.1%	0.6%	0.7%	0.7%	0.5%	0.8%	1.0%	1.1%	0.7%	0.8%	
PL	6,899	7,063	7,363	7,342	7,353	7,379	7,425	7,395	7,400	7,421	7,444	7,449	7,450	0.1%
				-0.3%	0.1%	0.4%	0.6%	-0.4%	0.1%	0.3%	0.3%	0.1%	0.0%	
PS	6,310	6,310	6,816	7,060	7,367	7,688	8,051	8,387	8,713	9,048	9,373	9,623	9,906	3.8%
				3.6%	4.3%	4.4%	4.7%	4.2%	3.9%	3.8%	3.6%	2.7%	2.9%	
RECO	199	199	225	232	240	248	258	266	274	283	292	300	308	3.2%
				3.1%	3.4%	3.3%	4.0%	3.1%	3.0%	3.3%	3.2%	2.7%	2.7%	
UGI	205	205	201	200	200	201	202	201	201	202	204	204	204	0.1%
				-0.5%	0.0%	0.5%	0.5%	-0.5%	0.0%	0.5%	1.0%	0.0%	0.0%	
DIVERSITY - MID-ATLANTIC(-)			604	733	747	737	431	584	608	642	593	460	448	
PJM MID-ATLANTIC	43,881	44,421	46,507	46,815	47,554	48,424	49,742	50,245	51,045	51,945	53,024	53,929	54,795	1.7%
				0.7%	1.6%	1.8%	2.7%	1.0%	1.6%	1.8%	2.1%	1.7%	1.6%	
FE-EAST	8,609	8,709	9,303	9,485	9,756	10,052	10,379	10,643	10,938	11,246	11,606	11,883	12,196	2.7%
				2.0%	2.9%	3.0%	3.3%	2.5%	2.8%	2.8%	3.2%	2.4%	2.6%	
PLGRP	7,104	7,268	7,561	7,541	7,553	7,575	7,620	7,587	7,596	7,612	7,637	7,642	7,647	0.1%
				-0.3%	0.2%	0.3%	0.6%	-0.4%	0.1%	0.2%	0.3%	0.1%	0.1%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2023/24).
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 2034/35 - 2038/39

	34/35	35/36	36/37	37/38	38/39	Annual Growth Rate (15 yr)
AE	2,223	2,294	2,355	2,420	2,489	2.8%
	2.9%	3.2%	2.7%	2.8%	2.9%	
BGE	6,414	6,519	6,608	6,703	6,803	1.0%
	1.6%	1.6%	1.4%	1.4%	1.5%	
DPL	3,946	3,994	4,022	4,058	4,105	0.7%
	0.8%	1.2%	0.7%	0.9%	1.2%	
JCPL	6,268	6,506	6,735	6,961	7,200	4.3%
	3.8%	3.8%	3.5%	3.4%	3.4%	
METED	3,464	3,580	3,672	3,786	3,912	2.4%
	2.9%	3.3%	2.6%	3.1%	3.3%	
PECO	7,026	7,102	7,152	7,211	7,285	0.7%
	0.8%	1.1%	0.7%	0.8%	1.0%	
PENLC	2,886	2,919	2,926	2,942	2,967	0.3%
	0.6%	1.1%	0.2%	0.5%	0.8%	
PEPCO	5,806	5,887	5,946	6,014	6,081	0.8%
	1.1%	1.4%	1.0%	1.1%	1.1%	
PL	7,477	7,514	7,546	7,577	7,617	0.2%
	0.4%	0.5%	0.4%	0.4%	0.5%	
PS	10,199	10,497	10,819	11,097	11,407	3.5%
	3.0%	2.9%	3.1%	2.6%	2.8%	
RECO	316	324	333	341	350	3.0%
	2.6%	2.5%	2.8%	2.4%	2.6%	
UGI	205	207	208	210	211	0.3%
	0.5%	1.0%	0.5%	1.0%	0.5%	
DIVERSITY - MID-ATLANTIC(-)	471	555	483	485	317	
PJM MID-ATLANTIC	55,759	56,788	57,839	58,835	60,110	1.7%
	1.8%	1.8%	1.9%	1.7%	2.2%	
FE-EAST	12,537	12,912	13,249	13,600	13,982	2.8%
	2.8%	3.0%	2.6%	2.6%	2.8%	
PLGRP	7,674	7,717	7,749	7,774	7,821	0.2%
	0.4%	0.6%	0.4%	0.3%	0.6%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2023/24).
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
2023/24 - 2033/34

	METERED 22/23	UNRESTRICTED 22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32	32/33	33/34	Annual Growth Rate (10 yr)
AEP	22,766	23,005	22,913	23,779	24,511	25,020	25,532	25,768	25,841	25,974	26,059	26,100	26,210	1.4%
				3.8%	3.1%	2.1%	2.0%	0.9%	0.3%	0.5%	0.3%	0.2%	0.4%	
APS	9,308	9,377	9,158	9,358	9,394	9,840	10,111	10,137	10,156	10,195	10,232	10,249	10,273	1.2%
				2.2%	0.4%	4.7%	2.8%	0.3%	0.2%	0.4%	0.4%	0.2%	0.2%	
ATSI	10,176	10,218	10,356	10,300	10,318	10,371	10,449	10,473	10,482	10,507	10,551	10,577	10,611	0.2%
				-0.5%	0.2%	0.5%	0.8%	0.2%	0.1%	0.2%	0.4%	0.2%	0.3%	
COMED	14,818	14,894	14,739	14,747	14,831	14,941	15,063	15,142	15,196	15,289	15,445	15,547	15,651	0.6%
				0.1%	0.6%	0.7%	0.8%	0.5%	0.4%	0.6%	1.0%	0.7%	0.7%	
DAYTON	3,006	3,015	2,943	2,926	2,930	2,941	2,956	2,951	2,940	2,938	2,944	2,947	2,947	0.0%
				-0.6%	0.1%	0.4%	0.5%	-0.2%	-0.4%	-0.1%	0.2%	0.1%	0.0%	
DEOK	4,933	4,936	4,566	4,547	4,548	4,570	4,605	4,587	4,593	4,599	4,623	4,631	4,632	0.1%
				-0.4%	0.0%	0.5%	0.8%	-0.4%	0.1%	0.1%	0.5%	0.2%	0.0%	
DLCO	2,033	2,039	1,997	1,992	2,001	2,016	2,035	2,046	2,056	2,075	2,095	2,114	2,133	0.7%
				-0.3%	0.5%	0.7%	0.9%	0.5%	0.5%	0.9%	1.0%	0.9%	0.9%	
EKPC	3,226	3,237	2,725	2,715	2,732	2,751	2,778	2,785	2,788	2,791	2,806	2,806	2,820	0.3%
				-0.4%	0.6%	0.7%	1.0%	0.3%	0.1%	0.1%	0.5%	0.0%	0.5%	
OVEC	89	89	110	110	110	110	110	110	110	110	110	110	110	0.0%
				0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
DIVERSITY - WESTERN(-)			1,880	1,859	1,746	1,765	1,948	1,881	1,738	1,704	1,645	1,614	1,602	
PJM WESTERN	70,188	70,708	67,627	68,615	69,629	70,795	71,691	72,118	72,424	72,774	73,220	73,467	73,785	0.9%
				1.5%	1.5%	1.7%	1.3%	0.6%	0.4%	0.5%	0.6%	0.3%	0.4%	
DOM	22,190	22,477	22,525	23,211	24,627	26,355	28,360	30,176	31,860	33,324	34,676	35,820	36,851	5.0%
				3.0%	6.1%	7.0%	7.6%	6.4%	5.6%	4.6%	4.1%	3.3%	2.9%	
DIVERSITY - TOTAL(-)			4,484	4,905	5,079	5,252	5,174	5,168	4,805	4,840	4,578	4,558	4,412	
PJM RTO	134,190	134,951	134,659	136,328	139,224	142,824	146,998	149,836	152,870	155,549	158,580	160,732	163,069	1.9%
				1.2%	2.1%	2.6%	2.9%	1.9%	2.0%	1.8%	1.9%	1.4%	1.5%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2023/24).
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
2034/35 - 2038/39

	34/35	35/36	36/37	37/38	38/39	Annual Growth Rate (15 yr)
AEP	26,281	26,349	26,415	26,517	26,680	1.0%
	0.3%	0.3%	0.3%	0.4%	0.6%	
APS	10,317	10,373	10,397	10,434	10,489	0.9%
	0.4%	0.5%	0.2%	0.4%	0.5%	
ATSI	10,664	10,714	10,762	10,813	10,877	0.3%
	0.5%	0.5%	0.4%	0.5%	0.6%	
COMED	15,813	15,982	16,107	16,267	16,435	0.7%
	1.0%	1.1%	0.8%	1.0%	1.0%	
DAYTON	2,950	2,958	2,964	2,976	2,996	0.1%
	0.1%	0.3%	0.2%	0.4%	0.7%	
DEOK	4,637	4,670	4,667	4,692	4,731	0.2%
	0.1%	0.7%	-0.1%	0.5%	0.8%	
DLCO	2,159	2,183	2,212	2,242	2,270	0.9%
	1.2%	1.1%	1.3%	1.4%	1.2%	
EKPC	2,826	2,844	2,846	2,858	2,873	0.4%
	0.2%	0.6%	0.1%	0.4%	0.5%	
OVEC	110	110	110	110	110	0.0%
	0.0%	0.0%	0.0%	0.0%	0.0%	
DIVERSITY - WESTERN(-)	1,569	1,515	1,290	1,166	1,225	
PJM WESTERN	74,188	74,668	75,190	75,743	76,236	0.8%
	0.5%	0.6%	0.7%	0.7%	0.7%	
DOM	37,931	39,005	40,112	41,250	42,273	4.3%
	2.9%	2.8%	2.8%	2.8%	2.5%	
DIVERSITY - TOTAL(-)	4,213	4,020	3,958	3,977	3,966	
PJM RTO	165,705	168,511	170,956	173,502	176,195	1.8%
	1.6%	1.7%	1.5%	1.5%	1.6%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2023/24).
Winter season indicates peak from December, January, February.

Table B-3

SPRING PEAK LOAD (MW) FOR
EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2024 - 2039

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
AE	1,742	1,743	1,739	1,746	1,775	1,797	1,816	1,846	1,888	1,927	1,971	2,023	2,045	2,094	2,151	2,202
BGE	5,179	5,177	5,193	5,213	5,258	5,304	5,339	5,385	5,446	5,527	5,617	5,724	5,800	5,897	6,017	6,129
DPL	3,133	3,117	3,119	3,130	3,147	3,161	3,173	3,185	3,208	3,248	3,271	3,316	3,330	3,375	3,430	3,465
JCPL	4,235	4,247	4,274	4,329	4,425	4,531	4,659	4,755	4,931	5,089	5,250	5,417	5,556	5,736	5,940	6,128
METED	2,471	2,495	2,546	2,606	2,682	2,746	2,800	2,857	2,932	3,036	3,121	3,222	3,311	3,427	3,540	3,689
PECO	6,466	6,437	6,450	6,455	6,554	6,613	6,656	6,640	6,645	6,755	6,818	6,923	6,944	6,993	7,047	7,199
PENLC	2,544	2,534	2,541	2,546	2,549	2,554	2,552	2,558	2,568	2,586	2,599	2,611	2,625	2,652	2,679	2,705
PEPCO	4,868	4,868	4,888	4,906	4,960	4,991	5,011	5,031	5,058	5,112	5,168	5,236	5,291	5,362	5,436	5,534
PL	6,281	6,255	6,299	6,336	6,355	6,371	6,375	6,360	6,397	6,441	6,466	6,476	6,468	6,520	6,584	6,631
PS	7,449	7,452	7,501	7,579	7,755	7,936	8,091	8,227	8,429	8,626	8,825	9,049	9,181	9,433	9,702	9,951
RECO	300	299	297	296	300	302	303	302	302	308	312	319	321	324	328	335
UGI	169	168	169	170	170	171	171	171	172	173	174	175	176	178	180	182
DIVERSITY - MID-ATLANTIC(-)	2,089	2,018	1,894	1,470	1,319	1,314	1,277	1,299	1,244	1,251	1,302	1,406	1,280	1,276	1,256	1,254
PJM MID-ATLANTIC	42,748	42,774	43,122	43,842	44,611	45,163	45,669	46,018	46,732	47,577	48,290	49,085	49,768	50,715	51,778	52,896
FE-EAST	8,790	8,871	9,008	9,233	9,440	9,628	9,824	10,020	10,245	10,576	10,833	11,115	11,324	11,641	11,999	12,383
PLGRP	6,448	6,422	6,468	6,502	6,519	6,542	6,544	6,524	6,565	6,612	6,635	6,644	6,641	6,692	6,762	6,811

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, 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
2024 - 2039

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
AEP	20,213	21,124	21,845	22,418	22,804	23,117	23,236	23,266	23,367	23,495	23,586	23,755	23,778	23,924	24,050	24,251
APS	7,891	8,072	8,199	8,577	8,814	8,859	8,881	8,848	8,929	8,985	9,004	9,084	9,012	9,118	9,221	9,258
ATSI	9,870	9,811	9,799	9,852	9,968	9,996	10,005	9,979	9,984	10,099	10,156	10,218	10,209	10,266	10,344	10,486
COMED	15,027	14,748	14,670	14,704	15,052	15,096	15,100	14,972	14,961	15,242	15,388	15,558	15,534	15,602	15,778	16,139
DAYTON	2,675	2,657	2,650	2,665	2,704	2,706	2,702	2,683	2,684	2,714	2,724	2,736	2,737	2,745	2,763	2,804
DEOK	4,357	4,321	4,324	4,328	4,375	4,393	4,400	4,382	4,381	4,434	4,463	4,492	4,489	4,517	4,540	4,632
DLCO	2,171	2,155	2,154	2,156	2,206	2,224	2,235	2,231	2,230	2,277	2,311	2,346	2,349	2,364	2,396	2,465
EKPC	2,127	2,134	2,151	2,168	2,184	2,194	2,204	2,212	2,221	2,229	2,236	2,240	2,262	2,273	2,291	2,304
OVEC	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
DIVERSITY - WESTERN(-)	2,983	2,790	2,634	2,760	2,660	2,832	2,978	2,702	2,571	2,610	2,654	2,756	2,592	2,431	2,458	2,456
PJM WESTERN	61,438	62,322	63,248	64,198	65,537	65,843	65,875	65,961	66,276	66,955	67,304	67,763	67,868	68,468	69,015	69,973
DOM	19,760	20,508	22,081	23,787	25,888	27,796	29,476	30,797	32,046	33,319	34,517	35,664	36,683	37,752	38,885	40,176
DIVERSITY - TOTAL(-)	7,312	6,937	6,700	6,666	6,757	6,994	6,883	6,464	6,507	6,322	6,131	6,360	6,254	6,197	6,243	6,259
PJM RTO	121,706	123,475	126,279	129,391	133,258	135,954	138,392	140,313	142,362	145,390	147,936	150,314	151,937	154,445	157,149	160,496

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, 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
2024 - 2039

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
AE	2,039	2,053	2,058	2,063	2,057	2,073	2,107	2,142	2,164	2,181	2,209	2,246	2,317	2,358	2,399	2,439
BGE	5,388	5,421	5,462	5,485	5,521	5,575	5,642	5,722	5,794	5,873	5,967	6,089	6,236	6,363	6,466	6,597
DPL	3,193	3,197	3,208	3,212	3,222	3,227	3,255	3,287	3,319	3,353	3,378	3,418	3,492	3,552	3,590	3,643
JCPL	4,766	4,829	4,881	4,928	4,959	5,037	5,133	5,255	5,358	5,484	5,626	5,752	5,956	6,139	6,283	6,451
METED	2,558	2,610	2,673	2,732	2,769	2,836	2,917	2,994	3,069	3,152	3,241	3,352	3,489	3,619	3,734	3,872
PECO	6,992	7,030	7,067	7,093	7,113	7,148	7,225	7,291	7,322	7,383	7,432	7,516	7,655	7,747	7,821	7,902
PENLC	2,524	2,532	2,546	2,554	2,557	2,559	2,576	2,596	2,614	2,633	2,648	2,667	2,710	2,742	2,770	2,798
PEPCO	5,127	5,174	5,209	5,235	5,250	5,291	5,339	5,412	5,449	5,509	5,581	5,648	5,786	5,891	5,971	6,065
PL	6,147	6,175	6,227	6,243	6,239	6,247	6,276	6,332	6,380	6,407	6,414	6,446	6,539	6,622	6,670	6,711
PS	8,297	8,419	8,521	8,603	8,686	8,824	8,994	9,150	9,292	9,415	9,573	9,771	10,041	10,299	10,470	10,676
RECO	326	330	331	329	325	324	333	337	339	340	341	347	359	366	369	374
UGI	167	167	168	169	169	169	170	171	173	174	175	176	177	180	182	184
DIVERSITY - MID-ATLANTIC(-)	1,100	997	973	935	1,205	1,194	1,010	1,082	1,102	1,198	1,173	1,260	1,161	1,116	1,269	1,295
PJM MID-ATLANTIC	46,424	46,940	47,378	47,711	47,662	48,116	48,957	49,607	50,171	50,706	51,412	52,168	53,596	54,762	55,456	56,417
FE-EAST	9,616	9,779	9,925	10,016	10,037	10,179	10,389	10,655	10,856	11,052	11,287	11,542	11,947	12,298	12,574	12,907
PLGRP	6,312	6,340	6,392	6,409	6,405	6,416	6,441	6,499	6,548	6,577	6,588	6,619	6,716	6,801	6,852	6,895

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, 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
2024 - 2039

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
AEP	20,714	21,824	22,553	23,043	23,454	23,533	23,826	24,080	24,168	24,283	24,378	24,351	24,757	24,979	25,132	25,311
APS	7,962	8,031	8,469	8,703	8,713	8,737	8,779	8,807	8,839	8,859	8,890	8,923	8,987	9,067	9,113	9,158
ATSI	10,664	10,829	10,878	10,901	10,772	10,758	10,809	10,986	11,030	11,016	10,966	11,015	11,277	11,378	11,452	11,503
COMED	17,307	17,361	17,408	17,382	17,343	17,264	17,329	17,525	17,520	17,644	17,784	17,777	18,101	18,311	18,475	18,618
DAYTON	2,921	2,948	2,970	2,971	2,952	2,941	2,963	2,990	3,000	3,000	3,000	2,999	3,060	3,097	3,107	3,123
DEOK	4,765	4,796	4,813	4,817	4,808	4,809	4,827	4,869	4,882	4,900	4,917	4,930	5,011	5,058	5,093	5,131
DLCO	2,345	2,361	2,378	2,393	2,391	2,403	2,422	2,457	2,480	2,500	2,519	2,531	2,597	2,642	2,671	2,710
EKPC	2,001	2,014	2,036	2,061	2,077	2,090	2,088	2,099	2,118	2,132	2,144	2,160	2,167	2,194	2,213	2,233
OVEC	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
DIVERSITY - WESTERN(-)	1,951	1,916	1,925	1,836	1,726	1,824	1,900	1,937	1,798	1,773	1,818	1,991	1,927	1,955	1,886	1,898
PJM WESTERN	66,808	68,328	69,660	70,515	70,864	70,791	71,223	71,956	72,319	72,641	72,860	72,775	74,110	74,851	75,450	75,969
DOM	20,254	21,219	23,239	25,130	27,451	29,431	31,139	32,630	34,071	35,434	36,762	37,975	39,250	40,551	41,857	43,208
DIVERSITY - TOTAL(-)	6,120	5,800	5,611	5,555	5,971	6,823	6,078	5,862	5,638	5,833	6,185	6,896	6,143	6,085	6,075	5,935
PJM RTO	130,417	133,600	137,564	140,572	142,937	144,533	148,151	151,350	153,823	155,919	157,840	159,273	163,901	167,150	169,843	172,852

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

Table B-5

MONTHLY PEAK FORECAST SCALED to SEASONAL PEAK (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 2024	1,637	5,827	3,700	3,817	2,740	6,597	2,829	5,359	7,363	6,816	225	201	604	46,507
Feb 2024	1,558	5,517	3,481	3,618	2,628	6,261	2,735	5,040	7,037	6,509	211	190	805	43,980
Mar 2024	1,389	4,939	3,133	3,228	2,406	5,484	2,544	4,457	6,281	5,934	192	169	858	39,298
Apr 2024	1,283	4,198	2,565	2,960	2,185	5,003	2,318	3,863	5,474	5,554	197	145	933	34,812
May 2024	1,742	5,179	3,104	4,235	2,471	6,466	2,353	4,868	5,758	7,449	300	149	1,326	42,748
Jun 2024	2,327	6,066	3,637	5,603	2,857	8,122	2,709	5,626	6,658	9,403	390	181	2,011	51,568
Jul 2024	2,593	6,491	3,945	6,052	3,036	8,581	2,867	6,053	7,126	10,068	410	197	1,586	55,833
Aug 2024	2,491	6,400	3,827	5,776	2,950	8,169	2,729	5,948	6,821	9,673	394	183	1,751	53,610
Sep 2024	2,039	5,388	3,193	4,766	2,558	6,992	2,524	5,127	6,147	8,297	326	167	1,100	46,424
Oct 2024	1,464	4,121	2,441	3,295	2,106	5,226	2,260	3,993	5,224	6,153	217	142	1,135	35,507
Nov 2024	1,369	4,362	2,685	3,246	2,233	5,266	2,417	4,015	5,808	5,934	201	164	618	37,082
Dec 2024	1,606	5,254	3,317	3,832	2,574	6,188	2,650	4,811	6,730	6,738	227	191	482	43,636

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	DIVERSITY	MID-ATLANTIC
Jan 2025	1,673	5,836	3,705	3,989	2,752	6,583	2,811	5,365	7,342	7,060	232	200	733	46,815
Feb 2025	1,566	5,453	3,432	3,709	2,593	6,129	2,656	4,976	6,878	6,641	214	187	722	43,712
Mar 2025	1,415	4,973	3,117	3,356	2,448	5,490	2,534	4,454	6,255	6,110	197	168	655	39,862
Apr 2025	1,297	4,235	2,545	3,046	2,233	5,005	2,313	3,889	5,485	5,668	200	144	906	35,154
May 2025	1,743	5,177	3,030	4,247	2,495	6,437	2,340	4,868	5,667	7,452	299	148	1,129	42,774
Jun 2025	2,336	6,080	3,606	5,631	2,906	8,171	2,725	5,665	6,709	9,500	394	183	2,116	51,790
Jul 2025	2,599	6,507	3,926	6,085	3,077	8,599	2,872	6,082	7,156	10,143	410	198	1,636	56,018
Aug 2025	2,496	6,407	3,797	5,792	2,984	8,182	2,733	5,970	6,840	9,759	393	184	1,705	53,832
Sep 2025	2,053	5,421	3,197	4,829	2,610	7,030	2,532	5,174	6,175	8,419	330	167	997	46,940
Oct 2025	1,477	4,150	2,436	3,354	2,149	5,237	2,248	4,002	5,216	6,249	219	142	1,088	35,791
Nov 2025	1,395	4,388	2,692	3,376	2,275	5,304	2,405	4,028	5,801	6,111	205	163	626	37,517
Dec 2025	1,647	5,305	3,356	4,045	2,628	6,235	2,661	4,845	6,777	7,019	234	191	287	44,656

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	DIVERSITY	MID-ATLANTIC
Jan 2026	1,721	5,855	3,730	4,208	2,799	6,616	2,815	5,397	7,353	7,367	240	200	747	47,554
Feb 2026	1,613	5,485	3,463	3,927	2,639	6,180	2,669	5,014	6,965	6,943	222	187	558	44,749
Mar 2026	1,457	5,014	3,119	3,553	2,511	5,548	2,541	4,547	6,299	6,382	203	169	131	41,212
Apr 2026	1,321	4,253	2,524	3,180	2,287	5,025	2,305	3,924	5,472	5,811	201	143	525	35,921
May 2026	1,739	5,193	2,987	4,274	2,546	6,450	2,319	4,888	5,652	7,501	297	147	871	43,122
Jun 2026	2,338	6,111	3,593	5,654	2,969	8,192	2,736	5,681	6,758	9,590	396	183	2,024	52,177
Jul 2026	2,602	6,523	3,913	6,099	3,141	8,640	2,885	6,104	7,196	10,224	411	198	1,603	56,333
Aug 2026	2,497	6,445	3,793	5,790	3,052	8,193	2,753	5,985	6,899	9,853	393	184	1,757	54,080
Sep 2026	2,058	5,462	3,208	4,881	2,673	7,067	2,546	5,209	6,227	8,521	331	168	973	47,378
Oct 2026	1,484	4,183	2,442	3,427	2,198	5,248	2,247	4,006	5,220	6,348	221	143	1,077	36,090
Nov 2026	1,443	4,463	2,721	3,551	2,370	5,385	2,437	4,122	5,898	6,365	213	167	544	38,591
Dec 2026	1,698	5,346	3,367	4,259	2,703	6,309	2,677	4,885	6,824	7,290	243	192	240	45,553

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.

Table B-5

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

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	OVEC	WESTERN DIVERSITY	PJM WESTERN	DOM	TOTAL DIVERSITY	PJM RTO
Jan 2024	22,913	9,158	10,356	14,739	2,943	4,566	1,997	2,725	95	1,865	67,627	22,525	4,469	134,659
Feb 2024	22,094	8,826	10,039	14,297	2,822	4,353	1,909	2,502	110	1,773	65,179	21,125	4,107	128,755
Mar 2024	20,213	7,891	9,188	12,461	2,546	3,839	1,743	2,127	90	109	59,989	19,359	2,530	117,083
Apr 2024	17,979	6,836	8,431	11,544	2,279	3,492	1,652	1,718	75	529	53,477	16,887	4,040	102,598
May 2024	19,275	7,314	9,870	15,027	2,675	4,357	2,171	1,661	65	977	61,438	19,760	4,543	121,706
Jun 2024	21,765	8,414	12,075	19,478	3,136	5,077	2,599	1,946	75	1,864	72,701	21,709	7,655	142,198
Jul 2024	22,902	8,835	12,433	20,414	3,319	5,332	2,705	2,070	90	1,571	76,529	22,781	7,053	151,247
Aug 2024	22,447	8,694	12,285	19,888	3,251	5,253	2,652	2,031	75	1,449	75,127	22,287	6,634	147,590
Sep 2024	20,714	7,962	10,664	17,307	2,921	4,765	2,345	1,856	70	1,796	66,808	20,254	5,965	130,417
Oct 2024	17,381	6,844	8,379	12,532	2,306	3,681	1,732	1,623	70	1,874	52,674	17,134	4,985	103,339
Nov 2024	18,886	7,550	8,847	12,461	2,406	3,601	1,700	2,001	80	1,447	56,085	18,438	3,867	109,803
Dec 2024	21,018	8,527	9,867	14,172	2,707	4,196	1,905	2,414	85	1,454	63,437	21,046	4,108	125,947

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	OVEC	DIVERSITY	WESTERN	DOM	DIVERSITY	PJM RTO
Jan 2025	23,779	9,358	10,300	14,747	2,926	4,547	1,992	2,715	95	1,844	68,615	23,211	4,890	136,328
Feb 2025	22,538	8,845	9,791	14,040	2,758	4,274	1,877	2,456	110	1,867	64,822	21,578	4,257	128,444
Mar 2025	21,124	8,072	9,179	12,525	2,541	3,829	1,740	2,134	90	34	61,200	20,107	956	120,902
Apr 2025	18,926	7,039	8,438	11,561	2,288	3,495	1,648	1,725	75	317	54,878	17,641	2,221	106,675
May 2025	20,142	7,462	9,811	14,748	2,657	4,321	2,155	1,660	65	699	62,322	20,508	3,957	123,475
Jun 2025	22,857	8,553	12,107	19,231	3,147	5,083	2,606	1,960	75	1,547	74,072	22,625	7,602	144,548
Jul 2025	23,893	8,968	12,421	20,380	3,322	5,339	2,707	2,088	90	1,612	77,596	23,691	7,060	153,493
Aug 2025	23,411	8,784	12,263	19,640	3,250	5,242	2,655	2,042	75	1,334	76,028	23,204	6,297	149,806
Sep 2025	21,824	8,031	10,829	17,361	2,948	4,796	2,361	1,877	70	1,769	68,328	21,219	5,653	133,600
Oct 2025	18,375	6,841	8,414	12,581	2,313	3,679	1,740	1,644	70	1,871	53,786	18,074	4,923	105,687
Nov 2025	19,886	7,587	8,847	12,485	2,413	3,595	1,706	2,014	80	1,500	57,113	19,310	4,126	111,940
Dec 2025	22,045	8,610	9,922	14,318	2,718	4,208	1,919	2,430	85	1,336	64,919	22,121	4,227	129,092

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	OVEC	DIVERSITY	WESTERN	DOM	DIVERSITY	PJM RTO
Jan 2026	24,511	9,394	10,318	14,831	2,930	4,548	2,001	2,732	95	1,731	69,629	24,627	5,064	139,224
Feb 2026	23,303	8,914	9,832	14,195	2,762	4,278	1,891	2,474	110	1,843	65,916	23,112	4,430	131,748
Mar 2026	21,845	8,199	9,254	12,649	2,551	3,842	1,760	2,151	90	0	62,341	21,645	770	124,559
Apr 2026	19,457	7,147	8,459	11,595	2,278	3,501	1,658	1,721	75	2	55,889	19,203	1,889	109,651
May 2026	20,763	7,607	9,799	14,670	2,650	4,324	2,154	1,674	65	458	63,248	22,081	3,501	126,279
Jun 2026	23,613	8,933	12,147	19,363	3,163	5,099	2,615	1,985	75	1,539	75,454	24,473	7,621	148,046
Jul 2026	24,607	9,356	12,432	20,372	3,329	5,356	2,716	2,105	90	1,552	78,811	25,627	7,123	156,803
Aug 2026	24,148	9,234	12,236	19,737	3,261	5,263	2,666	2,069	75	1,240	77,449	25,214	6,390	153,350
Sep 2026	22,553	8,469	10,878	17,408	2,970	4,813	2,378	1,911	70	1,790	69,660	23,239	5,476	137,564
Oct 2026	19,032	7,232	8,434	12,641	2,311	3,685	1,750	1,644	70	1,802	54,997	20,081	5,412	108,635
Nov 2026	20,659	8,058	9,014	12,714	2,435	3,654	1,730	2,036	80	1,357	59,023	21,385	3,387	117,513
Dec 2026	22,807	9,066	9,978	14,452	2,729	4,236	1,941	2,447	85	1,363	66,378	24,270	4,388	133,416

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.

Table B-6

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

	FE_EAST	PLGRP
Jan 2024	9,303	7,561
Feb 2024	8,901	7,209
Mar 2024	7,973	6,448
Apr 2024	7,233	5,617
May 2024	8,790	5,893
Jun 2024	10,899	6,839
Jul 2024	11,723	7,323
Aug 2024	11,268	7,004
Sep 2024	9,616	6,312
Oct 2024	7,411	5,357
Nov 2024	7,788	5,969
Dec 2024	9,019	6,921

	FE_EAST	PLGRP
Jan 2025	9,485	7,541
Feb 2025	8,920	7,064
Mar 2025	8,244	6,422
Apr 2025	7,451	5,621
May 2025	8,871	5,809
Jun 2025	11,014	6,891
Jul 2025	11,791	7,354
Aug 2025	11,315	7,024
Sep 2025	9,779	6,340
Oct 2025	7,528	5,344
Nov 2025	7,959	5,950
Dec 2025	9,271	6,968

	FE_EAST	PLGRP
Jan 2026	9,756	7,553
Feb 2026	9,218	7,152
Mar 2026	8,605	6,468
Apr 2026	7,682	5,612
May 2026	9,008	5,796
Jun 2026	11,104	6,933
Jul 2026	11,882	7,394
Aug 2026	11,431	7,079
Sep 2026	9,925	6,392
Oct 2026	7,666	5,353
Nov 2026	8,298	6,053
Dec 2026	9,560	7,016

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
FE_EAST contains JCPL, METED and PENLC zones. PLGRP contains PL and UGI zones.

Table B-7

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

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
AE																
CAPACITY PERFORMANCE	41	41	41	41	41	41	41	42	42	42	43	43	44	45	45	45
SUMMER PERIOD	7	7	7	7	8	8	8	8	8	8	8	8	8	8	8	8
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	48	48	48	48	49	49	49	50	50	50	51	51	52	53	53	53
BGE																
CAPACITY PERFORMANCE	102	102	102	103	103	104	105	105	106	107	109	110	112	114	115	116
SUMMER PERIOD	77	78	78	78	79	79	80	80	81	82	83	84	85	87	88	89
PRD	160	110	110	111	111	112	113	113	114	116	117	119	120	122	124	126
TOTAL LOAD MANAGEMENT	339	290	290	292	293	295	298	298	301	305	309	313	317	323	327	331
DPL																
CAPACITY PERFORMANCE	89	89	88	88	88	89	89	89	90	91	91	92	94	95	96	97
SUMMER PERIOD	89	89	88	88	88	89	89	89	90	91	91	92	94	95	96	97
PRD	35	38	38	38	38	38	38	38	39	39	39	40	40	41	41	41
TOTAL LOAD MANAGEMENT	213	216	214	214	214	216	216	216	219	221	221	224	228	231	233	235
JCPL																
CAPACITY PERFORMANCE	102	103	103	104	104	106	107	108	110	112	114	117	119	122	125	128
SUMMER PERIOD	5	5	5	5	5	5	5	5	5	5	6	6	6	6	6	6
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	107	108	108	109	109	111	112	113	115	117	120	123	125	128	131	134
METED																
CAPACITY PERFORMANCE	136	138	141	144	146	149	152	155	159	162	167	171	177	183	188	193
SUMMER PERIOD	25	25	26	26	27	27	28	29	29	30	31	32	33	34	35	36
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	161	163	167	170	173	176	180	184	188	192	198	203	210	217	223	229

Notes:
Summer-Period DR refers to DR resources that aggregate with Winter-Period resources to form a year-round commitment.
Forecast values for Capacity Performance and Summer-Period DR are based on actual committed quantities for Delivery Years 2021/22, 2022/23, 2023/24; forecast values for PRD are based on actual cleared quantities in the 2022/23, 2023/24 and 2024/25 RPM Base Residual Auctions

Table B-7 (Continued)

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

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
PECO																
CAPACITY PERFORMANCE	276	276	278	279	280	281	283	284	286	288	290	293	297	300	302	304
SUMMER PERIOD	28	28	28	28	28	28	28	28	29	29	29	29	30	30	30	30
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	304	304	306	307	308	309	311	312	315	317	319	322	327	330	332	334
PENLC																
CAPACITY PERFORMANCE	144	145	145	146	146	146	147	148	148	149	150	151	153	155	156	157
SUMMER PERIOD	86	86	87	87	87	87	87	88	88	89	89	90	91	92	93	94
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	230	231	232	233	233	233	234	236	236	238	239	241	244	247	249	251
PEPCO																
CAPACITY PERFORMANCE	96	97	97	97	98	98	99	100	101	101	102	103	105	106	107	108
SUMMER PERIOD	119	120	120	121	121	122	123	124	125	126	127	128	130	132	133	134
PRD	110	112	113	113	114	115	115	116	117	118	119	120	122	124	125	126
TOTAL LOAD MANAGEMENT	325	329	330	331	333	335	337	340	343	345	348	351	357	362	365	368
PL																
CAPACITY PERFORMANCE	322	323	325	326	326	327	328	330	331	332	333	335	339	342	344	346
SUMMER PERIOD	112	113	113	113	114	114	114	115	115	116	116	117	118	119	120	121
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	434	436	438	439	440	441	442	445	446	448	449	452	457	461	464	467
PS																
CAPACITY PERFORMANCE	153	154	156	157	158	160	162	164	165	168	170	173	176	179	183	187
SUMMER PERIOD	78	79	80	80	81	82	83	84	85	86	87	89	90	92	93	94
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	231	233	236	237	239	242	245	248	250	254	257	262	266	271	276	281

Notes:
Summer-Period DR refers to DR resources that aggregate with Winter-Period resources to form a year-round commitment.
Forecast values for Capacity Performance and Summer-Period DR are based on actual committed quantities for Delivery Years 2021/22, 2022/23, 2023/24; forecast values for PRD are based on actual cleared quantities in the 2022/23, 2023/24 and 2024/25 RPM Base Residual Auctions

Table B-7 (Continued)

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

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
RECO																
CAPACITY PERFORMANCE	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
SUMMER PERIOD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
UGI																
CAPACITY PERFORMANCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUMMER PERIOD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PJM MID-ATLANTIC																
CAPACITY PERFORMANCE	1,463	1,470	1,478	1,487	1,492	1,503	1,515	1,527	1,540	1,554	1,571	1,590	1,618	1,643	1,663	1,683
SUMMER PERIOD	626	630	632	633	638	641	645	650	655	662	667	675	685	695	702	709
PRD	305	260	261	262	263	265	266	267	270	273	275	279	282	287	290	293
TOTAL LOAD MANAGEMENT	2,394	2,360	2,371	2,382	2,393	2,409	2,426	2,444	2,465	2,489	2,513	2,544	2,585	2,625	2,655	2,685

Notes:
Summer-Period DR refers to DR resources that aggregate with Winter-Period resources to form a year-round commitment.
Forecast values for Capacity Performance and Summer-Period DR are based on actual committed quantities for Delivery Years 2021/22, 2022/23, 2023/24; forecast values for PRD are based on actual cleared quantities in the 2022/23, 2023/24 and 2024/25 RPM Base Residual Auctions

Table B-7 (Continued)

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

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
AEP																
CAPACITY PERFORMANCE	993	1,036	1,066	1,088	1,105	1,116	1,124	1,132	1,134	1,138	1,145	1,151	1,160	1,168	1,175	1,182
SUMMER PERIOD	296	309	318	324	329	333	335	337	338	339	341	343	346	348	351	354
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	1,289	1,345	1,384	1,412	1,434	1,449	1,459	1,469	1,472	1,477	1,486	1,494	1,506	1,516	1,526	1,536
APS																
CAPACITY PERFORMANCE	445	452	472	483	485	487	488	488	489	490	492	494	497	499	501	503
SUMMER PERIOD	136	138	144	147	148	148	148	149	149	149	150	150	151	152	153	154
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	581	590	616	630	633	635	636	637	638	639	642	644	648	651	654	657
ATSI																
CAPACITY PERFORMANCE	609	608	609	610	610	611	612	612	613	615	617	621	625	629	634	639
SUMMER PERIOD	169	169	169	170	170	170	170	170	170	171	172	173	174	175	176	177
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	778	777	778	780	780	781	782	782	783	786	789	794	799	804	810	816
COMED																
CAPACITY PERFORMANCE	1,001	1,000	999	999	997	991	991	993	994	998	1,001	1,005	1,014	1,024	1,030	1,036
SUMMER PERIOD	374	373	373	373	372	370	370	370	371	372	374	375	378	382	384	386
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	1,375	1,373	1,372	1,372	1,369	1,361	1,361	1,363	1,365	1,370	1,375	1,380	1,392	1,406	1,414	1,422
DAYTON																
CAPACITY PERFORMANCE	109	109	109	110	110	110	110	110	110	111	111	112	112	113	114	115
SUMMER PERIOD	58	58	59	59	59	59	59	59	59	59	60	60	60	61	61	61
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	167	167	168	169	169	169	169	169	169	170	171	172	172	174	175	176

Notes:
Summer-Period DR refers to DR resources that aggregate with Winter-Period resources to form a year-round commitment.
Forecast values for Capacity Performance and Summer-Period DR are based on actual committed quantities for Delivery Years 2021/22, 2022/23, 2023/24; forecast values for PRD are based on actual cleared quantities in the 2022/23, 2023/24 and 2024/25 RPM Base Residual Auctions

Table B-7 (Continued)

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

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
DEOK																
CAPACITY PERFORMANCE	128	128	129	129	129	129	129	130	130	131	131	132	133	134	135	136
SUMMER PERIOD	41	41	41	41	41	41	41	41	41	42	42	42	42	43	43	43
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	169	169	170	170	170	170	170	171	171	173	173	174	175	177	178	179
DLCO																
CAPACITY PERFORMANCE	64	64	64	64	64	65	65	66	66	66	67	68	69	70	71	72
SUMMER PERIOD	28	28	28	28	28	28	29	29	29	29	29	30	30	31	31	31
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	92	92	92	92	92	93	94	95	95	95	96	98	99	101	102	103
EKPC																
CAPACITY PERFORMANCE	120	121	122	123	124	124	125	126	126	127	128	129	130	131	132	133
SUMMER PERIOD	81	82	83	84	84	85	85	86	86	86	87	88	89	89	90	91
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	201	203	205	207	208	209	210	212	212	213	215	217	219	220	222	224
PJM WESTERN																
CAPACITY PERFORMANCE	3,469	3,518	3,570	3,606	3,624	3,633	3,644	3,657	3,662	3,676	3,692	3,712	3,740	3,768	3,792	3,816
SUMMER PERIOD	1,183	1,198	1,215	1,226	1,231	1,234	1,237	1,241	1,243	1,247	1,255	1,261	1,270	1,281	1,289	1,297
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	4,652	4,716	4,785	4,832	4,855	4,867	4,881	4,898	4,905	4,923	4,947	4,973	5,010	5,049	5,081	5,113

Notes:
Summer-Period DR refers to DR resources that aggregate with Winter-Period resources to form a year-round commitment.
Forecast values for Capacity Performance and Summer-Period DR are based on actual committed quantities for Delivery Years 2021/22, 2022/23, 2023/24; forecast values for PRD are based on actual cleared quantities in the 2022/23, 2023/24 and 2024/25 RPM Base Residual Auctions

Table B-7 (Continued)

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

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
DOM																
CAPACITY PERFORMANCE	604	628	679	729	790	842	887	925	962	999	1,034	1,068	1,100	1,133	1,167	1,202
SUMMER PERIOD	106	110	119	127	138	147	155	162	168	174	181	187	192	198	204	210
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	710	738	798	856	928	989	1,042	1,087	1,130	1,173	1,215	1,255	1,292	1,331	1,371	1,412
PJM RTO																
CAPACITY PERFORMANCE	5,536	5,616	5,727	5,822	5,906	5,978	6,046	6,109	6,164	6,229	6,297	6,370	6,458	6,544	6,622	6,701
SUMMER PERIOD	1,915	1,938	1,966	1,986	2,007	2,022	2,037	2,053	2,066	2,083	2,103	2,123	2,147	2,174	2,195	2,216
PRD	305	260	261	262	263	265	266	267	270	273	275	279	282	287	290	293
TOTAL LOAD MANAGEMENT	7,756	7,814	7,954	8,070	8,176	8,265	8,349	8,429	8,500	8,585	8,675	8,772	8,887	9,005	9,107	9,210

Notes:
Summer-Period DR refers to DR resources that aggregate with Winter-Period resources to form a year-round commitment.
Forecast values for Capacity Performance and Summer-Period DR are based on actual committed quantities for Delivery Years 2021/22, 2022/23, 2023/24; forecast values for PRD are based on actual cleared quantities in the 2022/23, 2023/24 and 2024/25 RPM Base Residual Auctions

Table B-8a

DISTRIBUTED SOLAR ADJUSTMENTS TO SUMMER PEAK LOAD (MW) FOR EACH PJM ZONE AND RTO
2024 - 2039

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
AE	130	122	115	115	118	116	112	115	117	117	121	124	122	123	126	128
BGE	211	219	239	249	259	275	286	306	300	297	299	307	319	330	335	345
DPL	120	135	137	133	135	143	142	144	145	141	141	146	149	153	156	159
JCPL	282	287	305	327	344	344	351	356	375	386	395	402	418	422	440	458
METED	51	53	54	55	57	58	57	59	62	63	66	69	72	76	82	92
PECO	68	77	86	96	107	119	129	141	155	168	182	195	206	216	225	239
PENLC	23	28	33	39	44	48	53	56	62	64	68	70	74	76	82	86
PEPCO	226	248	260	281	302	308	325	329	349	354	362	374	380	390	403	421
PL	127	133	138	146	151	157	162	173	184	195	203	207	216	224	232	239
PS	426	429	442	451	477	512	542	574	595	613	616	625	652	657	668	695
RECO	14	15	18	20	22	24	26	28	29	29	29	30	31	31	31	32
UGI	1	1	1	1	2	2	2	2	2	3	3	3	3	3	4	4
AEP	151	174	188	209	227	248	265	279	289	306	324	340	352	371	395	424
APS	94	104	113	122	130	141	152	163	173	184	197	203	213	219	223	229
ATSI	100	114	122	132	141	148	156	162	171	180	193	199	206	217	228	240
COMED	390	459	521	552	602	645	696	758	829	871	886	904	945	994	1,034	1,065
DAYTON	28	31	33	35	38	40	42	44	46	47	50	51	53	55	57	59
DEOK	21	26	29	32	35	39	43	47	51	54	58	63	67	72	77	81
DLCO	23	25	28	31	34	37	40	43	47	51	55	59	62	68	72	76
EKPC	5	5	6	7	8	9	11	12	14	15	17	18	20	22	23	24
OVEC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DOM	581	576	596	630	666	702	741	778	805	837	877	913	960	1,000	1,088	1,172
PJM RTO	3,136	3,446	3,773	4,109	4,409	4,470	4,657	4,858	4,965	5,005	5,103	5,279	5,441	5,641	5,921	6,387

Notes:
Adjustment values presented here are average summer peak distribution forecast values.

Values are derived by PJM from a forecast obtained from SPGCI.

Table B-8b

DISTRIBUTED BATTERY STORAGE ADJUSTMENT TO SUMMER PEAK LOAD (MW) FOR EACH PJM ZONE AND RTO
2024 - 2039

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
AE	1	2	3	5	7	9	11	13	14	15	17	18	19	21	22	25
BGE	2	4	7	10	13	17	23	35	50	65	80	95	107	120	132	143
DPL	1	1	2	3	4	6	7	11	14	18	21	24	27	30	33	36
JCPL	2	4	8	12	16	21	26	30	34	37	40	43	46	50	55	61
METED	0	1	1	1	2	2	3	4	4	5	6	6	7	7	7	8
PECO	1	2	2	3	4	6	7	9	11	12	14	16	16	17	18	19
PENLC	0	1	1	1	2	2	3	4	5	5	6	7	7	7	8	8
PEPCO	2	4	7	9	12	16	21	30	41	52	63	74	84	94	103	113
PL	1	2	3	3	5	6	7	9	11	13	15	16	17	18	19	19
PS	3	7	14	22	30	39	47	54	62	67	71	76	82	89	97	107
RECO	0	0	0	1	1	1	2	2	2	3	3	3	3	3	4	4
UGI	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AEP	2	5	7	10	13	17	21	25	30	34	39	43	47	51	55	59
APS	1	2	4	5	7	10	13	18	24	30	37	43	48	54	59	63
ATSI	1	3	5	6	8	10	12	14	16	18	20	22	23	25	26	28
COMED	4	10	17	24	32	40	49	60	72	81	87	95	102	110	117	124
DAYTON	0	1	1	2	2	3	3	4	4	5	5	6	6	7	7	8
DEOK	1	1	2	2	3	4	5	5	6	7	8	8	9	10	11	11
DLCO	0	1	1	1	1	2	2	3	4	4	5	5	5	6	6	6
EKPC	0	0	0	0	0	0	1	1	1	1	2	2	3	3	4	4
OVEC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DOM	3	8	13	18	25	35	47	61	78	92	105	115	123	131	137	143
PJM RTO	25	57	98	141	189	247	310	392	484	567	644	717	784	853	920	989

Notes:
Adjustment values presented here are reflected in all summer peak forecast values.

Values are derived by PJM from a forecast obtained from SPGCI.

Table B-8c

PLUG IN ELECTRIC VEHICLE ADJUSTMENT TO SUMMER PEAK LOAD (MW) FOR EACH PJM ZONE AND RTO
2024 - 2039

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
AE	12	30	54	80	107	137	168	204	243	284	329	375	419	466	509	561
BGE	36	79	136	198	264	342	428	530	644	759	883	1,014	1,141	1,283	1,406	1,555
DPL	12	30	53	79	105	133	164	200	239	279	323	371	418	466	509	561
JCPL	53	113	194	283	377	483	588	713	847	986	1,136	1,297	1,452	1,610	1,760	1,942
METED	15	36	66	98	133	173	215	268	328	394	468	553	641	739	840	958
PECO	24	50	84	120	158	201	246	303	367	433	505	587	668	755	837	936
PENLC	5	13	26	39	54	70	88	111	137	165	195	228	261	297	332	373
PEPCO	33	62	101	141	183	233	287	349	417	488	564	644	724	811	893	988
PL	10	22	40	58	78	101	124	153	186	221	259	301	342	387	432	484
PS	60	128	222	325	433	549	673	821	975	1,138	1,315	1,504	1,684	1,870	2,047	2,252
RECO	2	4	7	9	12	15	19	23	27	31	36	41	46	51	56	62
UGI	1	1	2	3	4	5	6	8	10	12	14	16	18	20	23	25
AEP	25	60	108	158	213	277	346	433	529	635	753	883	1,013	1,158	1,302	1,477
APS	9	22	40	60	81	104	129	161	196	234	274	317	358	403	446	496
ATSI	21	49	85	125	167	214	262	324	394	472	556	650	744	848	954	1,077
COMED	76	160	269	386	506	635	768	928	1,102	1,293	1,488	1,696	1,905	2,123	2,338	2,593
DAYTON	4	9	16	23	31	40	49	61	74	89	105	124	143	164	185	210
DEOK	11	21	36	51	66	84	103	126	152	180	211	246	280	319	357	402
DLCO	10	21	36	53	70	89	109	135	163	194	229	266	302	343	386	433
EKPC	2	6	11	16	21	28	34	43	53	63	75	88	101	115	130	146
OVEC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DOM	67	150	259	374	498	636	779	959	1,159	1,378	1,605	1,852	2,095	2,360	2,625	2,954
PJM RTO	501	1,085	1,873	2,707	3,587	4,605	5,647	6,927	8,342	9,847	11,442	13,159	14,809	16,586	18,269	20,322

Notes:
Adjustment values presented here are average summer peak distribution forecast values.

Values are derived by PJM from a forecast obtained from SPGCI.

Table B-9

ADJUSTMENTS ABOVE EMBEDDED TO SUMMER PEAK LOAD (MW) FOR EACH PJM ZONE AND RTO
2024 - 2039

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
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	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
PEPCO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PL	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PS	16	49	83	142	197	252	295	298	312	329	347	364	383	401	420	439
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	767	1,738	2,419	2,871	3,218	3,432	3,544	3,638	3,626	3,627	3,634	3,621	3,641	3,647	3,638	3,624
APS	73	213	566	803	803	803	803	803	803	803	803	803	803	803	803	803
ATSI	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
COMED	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DAYTON	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
DEOK	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
DLCO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EKPC	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5
OVEC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DOM	1,801	2,666	4,482	6,241	8,417	10,263	11,831	13,118	14,319	15,491	16,605	17,610	18,521	19,514	20,533	21,563
PJM RTO	2,664	4,673	7,557	10,064	12,643	14,757	16,480	17,864	19,067	20,258	21,397	22,406	23,355	24,372	25,403	26,436

Notes:
Adjustment values presented here are reflected in summer peak forecasts.
Adjustments due to NRBTMG (Non-Retail Behind the Meter Generation) transitioning to DR are in AEP, ATSI, DAYTON, DEOK, PL, and PENLC.
Adjustments due to data center load growth are in AEP, APS, DOM, and PS.
Adjustments due to planned chip processing plant in AEP.
Adjustments due to Port Electrification are in PS.
An adjustment due to peak shaving program is in EKPC.

Table B-10

SUMMER COINCIDENT PEAK LOAD (MW) FOR
EACH PJM ZONE, LOCATIONAL DELIVERABILITY AREA AND RTO
2024 - 2039

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
AE	2,350	2,355	2,357	2,354	2,356	2,368	2,374	2,394	2,425	2,457	2,497	2,541	2,580	2,627	2,655	2,688
BGE	6,238	6,259	6,285	6,303	6,328	6,370	6,406	6,460	6,517	6,576	6,664	6,770	6,883	6,992	7,080	7,210
DPL	3,706	3,673	3,654	3,642	3,641	3,647	3,645	3,660	3,690	3,723	3,762	3,813	3,863	3,913	3,942	3,984
JCPL	5,693	5,719	5,742	5,760	5,808	5,854	5,912	6,009	6,119	6,250	6,398	6,558	6,722	6,891	7,023	7,202
METED	2,917	2,958	3,019	3,082	3,145	3,207	3,268	3,340	3,414	3,498	3,595	3,706	3,824	3,949	4,066	4,204
PECO	8,103	8,119	8,146	8,177	8,206	8,212	8,240	8,272	8,307	8,342	8,414	8,506	8,595	8,694	8,774	8,881
PENLC	2,742	2,745	2,755	2,766	2,775	2,783	2,793	2,811	2,825	2,844	2,868	2,897	2,930	2,964	2,994	3,029
PEPCO	5,787	5,818	5,851	5,875	5,909	5,943	5,973	6,011	6,043	6,079	6,141	6,218	6,306	6,387	6,458	6,558
PL	6,835	6,854	6,887	6,912	6,938	6,946	6,964	6,996	7,017	7,046	7,086	7,137	7,202	7,278	7,326	7,390
PS	9,521	9,584	9,638	9,699	9,802	9,909	10,019	10,129	10,265	10,433	10,625	10,828	11,048	11,277	11,443	11,668
RECO	388	388	387	385	385	383	383	385	386	390	394	398	403	409	413	420
UGI	186	186	187	187	188	187	188	188	189	190	191	193	195	197	198	201
AEP	22,306	23,296	24,038	24,595	25,015	25,275	25,425	25,574	25,660	25,752	25,863	26,049	26,260	26,391	26,589	26,782
APS	8,680	8,836	9,209	9,482	9,519	9,548	9,565	9,575	9,585	9,605	9,632	9,677	9,732	9,764	9,806	9,853
ATSI	11,980	11,978	11,998	12,043	12,066	12,082	12,071	12,086	12,119	12,161	12,193	12,253	12,336	12,394	12,485	12,564
COMED	18,835	18,839	18,807	18,851	18,781	18,822	18,806	18,805	18,792	18,861	18,930	19,094	19,244	19,347	19,488	19,624
DAYTON	3,133	3,135	3,148	3,165	3,165	3,173	3,173	3,174	3,183	3,190	3,199	3,220	3,245	3,262	3,292	3,314
DEOK	5,074	5,076	5,094	5,119	5,132	5,144	5,143	5,148	5,167	5,187	5,211	5,246	5,287	5,316	5,363	5,404
DLCO	2,619	2,622	2,634	2,650	2,668	2,685	2,698	2,713	2,733	2,755	2,778	2,809	2,841	2,872	2,910	2,951
EKPC	1,958	1,973	1,993	2,021	2,042	2,059	2,070	2,081	2,095	2,112	2,129	2,152	2,174	2,190	2,210	2,226
OVEC	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
DOM	22,134	23,021	24,915	26,731	29,044	31,023	32,700	34,139	35,520	36,856	38,194	39,498	40,756	41,953	43,175	44,538
PJM RTO	151,245	153,494	156,804	159,859	162,973	165,680	167,876	170,010	172,111	174,367	176,824	179,623	182,486	185,127	187,750	190,751
PJM MID-ATLANTIC	54,466	54,658	54,908	55,142	55,481	55,809	56,165	56,655	57,197	57,828	58,635	59,565	60,551	61,578	62,372	63,435
EASTERN MID-ATLANTIC	29,761	29,838	29,924	30,017	30,198	30,373	30,573	30,849	31,192	31,595	32,090	32,644	33,211	33,811	34,250	34,843
SOUTHERN MID-ATLANTIC	12,025	12,077	12,136	12,178	12,237	12,313	12,379	12,471	12,560	12,655	12,805	12,988	13,189	13,379	13,538	13,768

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, 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 2024
SUMMER TOTAL INTERNAL DEMAND FORECAST (MW) FOR EACH NERC REGION
2024 - 2039

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Annual Growth Rate (10 yr)
PJM - RELIABILITY FIRST												
TOTAL INTERNAL DEMAND	127,155	128,499	129,895	131,107	131,886	132,599	133,103	133,788	134,494	135,398	136,499	0.7%
% GROWTH TOTAL		1.1%	1.1%	0.9%	0.6%	0.5%	0.4%	0.5%	0.5%	0.7%	0.8%	
CONTRACTUALLY INTERRUPTIBLE	6,845	6,873	6,951	7,007	7,040	7,067	7,097	7,130	7,158	7,199	7,245	
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	6,845	6,873	6,951	7,007	7,040	7,067	7,097	7,130	7,158	7,199	7,245	
NET INTERNAL DEMAND	120,310	121,626	122,944	124,100	124,846	125,532	126,006	126,658	127,336	128,199	129,254	0.7%
% GROWTH NET		1.1%	1.1%	0.9%	0.6%	0.5%	0.4%	0.5%	0.5%	0.7%	0.8%	
PJM - SERC												
TOTAL INTERNAL DEMAND	24,092	24,994	26,908	28,752	31,086	33,082	34,770	36,220	37,615	38,968	40,323	5.3%
% GROWTH TOTAL		3.7%	7.7%	6.9%	8.1%	6.4%	5.1%	4.2%	3.9%	3.6%	3.5%	
CONTRACTUALLY INTERRUPTIBLE	911	941	1,003	1,063	1,136	1,198	1,252	1,299	1,342	1,386	1,430	
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	911	941	1,003	1,063	1,136	1,198	1,252	1,299	1,342	1,386	1,430	
NET INTERNAL DEMAND	23,181	24,053	25,905	27,689	29,950	31,884	33,518	34,921	36,273	37,582	38,893	5.3%
% GROWTH NET		3.8%	7.7%	6.9%	8.2%	6.5%	5.1%	4.2%	3.9%	3.6%	3.5%	
PJM RTO												
TOTAL INTERNAL DEMAND	151,247	153,493	156,803	159,859	162,972	165,681	167,873	170,008	172,109	174,366	176,822	1.6%
% GROWTH TOTAL		1.5%	2.2%	1.9%	1.9%	1.7%	1.3%	1.3%	1.2%	1.3%	1.4%	
CONTRACTUALLY INTERRUPTIBLE	7,756	7,814	7,954	8,070	8,176	8,265	8,349	8,429	8,500	8,585	8,675	
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	7,756	7,814	7,954	8,070	8,176	8,265	8,349	8,429	8,500	8,585	8,675	
NET INTERNAL DEMAND	143,491	145,679	148,849	151,789	154,796	157,416	159,524	161,579	163,609	165,781	168,147	1.6%
% GROWTH NET		1.5%	2.2%	2.0%	2.0%	1.7%	1.3%	1.3%	1.3%	1.3%	1.4%	

Notes:
SERC includes EKPC and DOM zones and Reliability First includes all other zones.
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 (2024).

Table B-11 (Continued)

PJM CONTROL AREA - JANUARY 2024
SUMMER TOTAL INTERNAL DEMAND FORECAST (MW) FOR EACH NERC REGION
2024 - 2039

	2035	2036	2037	2038	2039	Annual Growth Rate (15 yr)
PJM - RELIABILITY FIRST						
TOTAL INTERNAL DEMAND	137,972	139,557	140,984	142,367	143,988	0.8%
% GROWTH TOTAL	1.1%	1.1%	1.0%	1.0%	1.1%	
CONTRACTUALLY INTERRUPTIBLE	7,300	7,376	7,454	7,514	7,574	
DIRECT CONTROL	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	7,300	7,376	7,454	7,514	7,574	
NET INTERNAL DEMAND	130,672	132,181	133,530	134,853	136,414	0.8%
% GROWTH NET	1.1%	1.2%	1.0%	1.0%	1.2%	
PJM - SERC						
TOTAL INTERNAL DEMAND	41,650	42,930	44,143	45,385	46,764	4.5%
% GROWTH TOTAL	3.3%	3.1%	2.8%	2.8%	3.0%	
CONTRACTUALLY INTERRUPTIBLE	1,472	1,511	1,551	1,593	1,636	
DIRECT CONTROL	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	1,472	1,511	1,551	1,593	1,636	
NET INTERNAL DEMAND	40,178	41,419	42,592	43,792	45,128	4.5%
% GROWTH NET	3.3%	3.1%	2.8%	2.8%	3.1%	
PJM RTO						
TOTAL INTERNAL DEMAND	179,622	182,487	185,127	187,752	190,752	1.6%
% GROWTH TOTAL	1.6%	1.6%	1.4%	1.4%	1.6%	
CONTRACTUALLY INTERRUPTIBLE	8,772	8,887	9,005	9,107	9,210	
DIRECT CONTROL	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	8,772	8,887	9,005	9,107	9,210	
NET INTERNAL DEMAND	170,850	173,600	176,122	178,645	181,542	1.6%
% GROWTH NET	1.6%	1.6%	1.5%	1.4%	1.6%	

Notes:
SERC includes EKPC and DOM zones and Reliability First includes all other zones.
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 (2024).

Table B-12

PJM CONTROL AREA - JANUARY 2024
WINTER TOTAL INTERNAL DEMAND FORECAST (MW) FOR EACH NERC REGION
2023/24 - 2033/34

	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32	32/33	33/34	Annual Growth Rate (10 yr)
PJM - RELIABILITY FIRST												
TOTAL INTERNAL DEMAND	128,820	129,272	132,104	135,649	139,777	142,586	145,617	148,288	151,266	153,407	155,711	1.9%
% GROWTH TOTAL		0.4%	2.2%	2.7%	3.0%	2.0%	2.1%	1.8%	2.0%	1.4%	1.5%	
CONTRACTUALLY INTERRUPTIBLE	4,812	4,867	4,926	4,970	4,992	5,012	5,034	5,058	5,076	5,103	5,135	
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	4,812	4,867	4,926	4,970	4,992	5,012	5,034	5,058	5,076	5,103	5,135	
NET INTERNAL DEMAND	124,008	124,405	127,178	130,679	134,785	137,574	140,583	143,230	146,190	148,304	150,576	2.0%
% GROWTH NET		0.3%	2.2%	2.8%	3.1%	2.1%	2.2%	1.9%	2.1%	1.4%	1.5%	
PJM - SERC												
TOTAL INTERNAL DEMAND	5,839	7,056	7,120	7,175	7,221	7,250	7,253	7,261	7,314	7,325	7,358	2.3%
% GROWTH TOTAL		20.8%	0.9%	0.8%	0.6%	0.4%	0.0%	0.1%	0.7%	0.2%	0.5%	
CONTRACTUALLY INTERRUPTIBLE	724	749	801	852	914	966	1,012	1,051	1,088	1,126	1,162	
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	724	749	801	852	914	966	1,012	1,051	1,088	1,126	1,162	
NET INTERNAL DEMAND	5,115	6,307	6,319	6,323	6,307	6,284	6,241	6,210	6,226	6,199	6,196	1.9%
% GROWTH NET		23.3%	0.2%	0.1%	-0.3%	-0.4%	-0.7%	-0.5%	0.3%	-0.4%	-0.0%	
PJM RTO												
TOTAL INTERNAL DEMAND	134,659	136,328	139,224	142,824	146,998	149,836	152,870	155,549	158,580	160,732	163,069	1.9%
% GROWTH TOTAL		1.2%	2.1%	2.6%	2.9%	1.9%	2.0%	1.8%	1.9%	1.4%	1.5%	
CONTRACTUALLY INTERRUPTIBLE	5,536	5,616	5,727	5,822	5,906	5,978	6,046	6,109	6,164	6,229	6,297	
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	5,536	5,616	5,727	5,822	5,906	5,978	6,046	6,109	6,164	6,229	6,297	
NET INTERNAL DEMAND	129,123	130,712	133,497	137,002	141,092	143,858	146,824	149,440	152,416	154,503	156,772	2.0%
% GROWTH NET		1.2%	2.1%	2.6%	3.0%	2.0%	2.1%	1.8%	2.0%	1.4%	1.5%	

Notes:
SERC includes EKPC and DOM zones and Reliability First includes all other zones.
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 (2024).

Table B-12 (Continued)

PJM CONTROL AREA - JANUARY 2024
WINTER TOTAL INTERNAL DEMAND FORECAST (MW) FOR EACH NERC REGION
2023/24 - 2033/34

	34/35	35/36	36/37	37/38	38/39	Annual Growth Rate (15 yr)
PJM - RELIABILITY FIRST						
TOTAL INTERNAL DEMAND	158,331	161,113	163,510	166,015	168,681	1.8%
% GROWTH TOTAL	1.7%	1.8%	1.5%	1.5%	1.6%	
CONTRACTUALLY INTERRUPTIBLE	5,173	5,228	5,280	5,323	5,366	
DIRECT CONTROL	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	5,173	5,228	5,280	5,323	5,366	
NET INTERNAL DEMAND	153,158	155,885	158,230	160,692	163,315	1.9%
% GROWTH NET	1.7%	1.8%	1.5%	1.6%	1.6%	
PJM - SERC						
TOTAL INTERNAL DEMAND	7,374	7,398	7,446	7,487	7,514	1.7%
% GROWTH TOTAL	0.2%	0.3%	0.6%	0.6%	0.4%	
CONTRACTUALLY INTERRUPTIBLE	1,197	1,230	1,264	1,299	1,335	
DIRECT CONTROL	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	1,197	1,230	1,264	1,299	1,335	
NET INTERNAL DEMAND	6,177	6,168	6,182	6,188	6,179	1.3%
% GROWTH NET	-0.3%	-0.1%	0.2%	0.1%	-0.1%	
PJM RTO						
TOTAL INTERNAL DEMAND	165,705	168,511	170,956	173,502	176,195	1.8%
% GROWTH TOTAL	1.6%	1.7%	1.5%	1.5%	1.6%	
CONTRACTUALLY INTERRUPTIBLE	6,370	6,458	6,544	6,622	6,701	
DIRECT CONTROL	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	6,370	6,458	6,544	6,622	6,701	
NET INTERNAL DEMAND	159,335	162,053	164,412	166,880	169,494	1.8%
% GROWTH NET	1.6%	1.7%	1.5%	1.5%	1.6%	

Notes:
SERC includes EKPC and DOM zones and Reliability First includes all other zones.
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 (2024).

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
2024	18,425	22,639	19,025	21,298
2025	18,355	22,754	19,216	21,339
2026	18,540	22,900	19,429	21,487
2027	18,745	23,035	19,541	21,620
2028	18,908	23,159	19,572	21,830
2029	19,073	23,328	19,777	21,960
2030	19,200	23,475	20,004	22,089
2031	19,266	23,659	20,347	22,302
2032	19,537	23,858	20,614	22,573
2033	19,752	24,115	20,815	22,827
2034	20,074	24,389	21,030	22,971
2035	20,437	24,687	21,344	23,245
2036	20,610	25,043	21,916	23,567
2037	20,870	25,442	22,374	23,840
2038	21,245	25,835	22,711	24,158
2039	21,778	26,270	23,108	24,503

EXTREME WEATHER (90/10) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2024	20,151	24,122	20,957	22,784
2025	20,120	24,394	21,085	22,762
2026	20,333	24,515	21,233	22,868
2027	20,525	24,473	21,380	22,985
2028	20,630	24,611	21,591	23,174
2029	20,764	24,920	21,624	23,169
2030	20,849	24,955	21,809	23,281
2031	20,894	25,163	22,083	23,389
2032	21,157	25,319	22,367	23,692
2033	21,297	25,577	22,747	23,808
2034	21,559	25,884	22,979	24,052
2035	21,859	26,204	23,225	24,335
2036	22,118	26,596	23,762	24,680
2037	22,394	26,935	24,180	24,905
2038	22,728	27,329	24,616	25,212
2039	23,172	27,767	25,080	25,518

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, 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
2024	11,400	13,072	11,278	13,055
2025	11,381	13,165	11,374	13,029
2026	11,487	13,278	11,515	13,092
2027	11,585	13,372	11,616	13,154
2028	11,654	13,410	11,636	13,280
2029	11,715	13,525	11,700	13,311
2030	11,768	13,585	11,843	13,391
2031	11,795	13,752	12,004	13,468
2032	11,949	13,872	12,142	13,591
2033	12,089	13,993	12,254	13,686
2034	12,221	14,107	12,382	13,797
2035	12,366	14,305	12,524	13,928
2036	12,451	14,526	12,793	14,113
2037	12,652	14,790	13,049	14,265
2038	12,875	14,982	13,243	14,445
2039	13,096	15,233	13,449	14,628

EXTREME WEATHER (90/10) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2024	12,320	13,778	12,435	13,688
2025	12,357	13,838	12,509	13,686
2026	12,466	13,927	12,598	13,741
2027	12,536	14,012	12,683	13,810
2028	12,539	14,112	12,789	13,903
2029	12,587	14,203	12,878	13,968
2030	12,629	14,273	12,993	14,038
2031	12,679	14,444	13,119	14,111
2032	12,800	14,526	13,239	14,231
2033	12,915	14,655	13,384	14,307
2034	13,029	14,835	13,543	14,429
2035	13,175	15,012	13,706	14,565
2036	13,357	15,239	13,959	14,781
2037	13,538	15,454	14,172	14,882
2038	13,711	15,674	14,367	15,049
2039	13,889	15,920	14,601	15,223

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, 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
2024	22,569	31,179	25,288	22,582
2025	22,504	31,260	25,531	23,023
2026	22,525	31,341	25,741	23,681
2027	22,740	31,413	25,878	24,382
2028	23,295	31,525	25,971	25,186
2029	23,715	31,777	26,253	25,815
2030	24,038	31,942	26,632	26,484
2031	24,317	32,231	27,030	27,201
2032	24,833	32,571	27,329	27,950
2033	25,386	32,968	27,719	28,578
2034	25,846	33,407	28,114	29,219
2035	26,317	33,944	28,631	29,926
2036	26,698	34,470	29,344	30,621
2037	27,165	35,105	29,947	31,305
2038	27,683	35,585	30,392	31,996
2039	28,416	36,148	30,981	32,738

EXTREME WEATHER (90/10) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2024	25,843	33,610	28,228	23,658
2025	25,715	33,752	28,410	24,151
2026	25,629	33,853	28,548	24,817
2027	25,670	33,852	28,790	25,594
2028	26,154	34,011	29,032	26,433
2029	26,605	34,095	29,282	27,150
2030	26,651	34,562	29,621	27,851
2031	26,590	34,888	30,045	28,579
2032	26,752	35,041	30,299	29,429
2033	27,427	35,447	30,782	30,068
2034	28,032	35,909	31,312	30,700
2035	28,506	36,395	31,782	31,470
2036	28,800	37,042	32,378	32,308
2037	29,299	37,560	32,875	32,876
2038	29,965	38,073	33,371	33,644
2039	30,802	38,676	34,033	34,467

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, 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
2024	9,870	12,465	10,488	11,186
2025	9,894	12,501	10,592	11,201
2026	9,941	12,555	10,668	11,252
2027	9,995	12,632	10,709	11,333
2028	10,082	12,686	10,681	11,417
2029	10,181	12,750	10,749	11,471
2030	10,266	12,831	10,884	11,562
2031	10,314	12,925	11,134	11,666
2032	10,388	13,015	11,198	11,819
2033	10,558	13,137	11,337	11,938
2034	10,707	13,254	11,489	12,043
2035	10,866	13,408	11,648	12,220
2036	10,993	13,603	11,957	12,392
2037	11,152	13,819	12,179	12,545
2038	11,358	14,004	12,394	12,706
2039	11,594	14,241	12,597	12,872

EXTREME WEATHER (90/10) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2024	10,978	13,518	11,549	12,046
2025	10,961	13,585	11,613	12,050
2026	10,989	13,587	11,678	12,094
2027	11,035	13,629	11,735	12,207
2028	11,138	13,664	11,822	12,276
2029	11,212	13,730	11,914	12,295
2030	11,250	13,806	12,004	12,316
2031	11,278	13,889	12,140	12,371
2032	11,335	13,958	12,267	12,523
2033	11,528	14,079	12,427	12,620
2034	11,673	14,223	12,603	12,745
2035	11,815	14,393	12,780	12,882
2036	11,914	14,609	13,028	13,064
2037	12,035	14,823	13,253	13,123
2038	12,242	14,998	13,478	13,289
2039	12,547	15,198	13,756	13,440

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, 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 2024 - 2039

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
AE	2,742	2,742	2,744	2,746	2,761	2,775	2,785	2,795	2,815	2,836	2,879	2,924	2,943	2,993	3,035	3,065
BGE	7,103	7,118	7,131	7,144	7,158	7,179	7,219	7,275	7,326	7,373	7,457	7,568	7,686	7,804	7,918	8,050
DPL	4,159	4,129	4,120	4,128	4,137	4,152	4,166	4,195	4,230	4,263	4,304	4,352	4,405	4,457	4,504	4,557
JCPL	6,681	6,706	6,709	6,704	6,728	6,754	6,823	6,905	7,006	7,112	7,245	7,404	7,573	7,733	7,871	8,050
METED	3,185	3,229	3,287	3,351	3,411	3,479	3,547	3,624	3,694	3,784	3,880	3,988	4,110	4,238	4,365	4,510
PECO	9,180	9,225	9,257	9,263	9,309	9,339	9,376	9,450	9,464	9,525	9,598	9,692	9,795	9,895	9,983	10,103
PENLC	2,998	2,998	3,005	3,012	3,016	3,023	3,039	3,064	3,068	3,084	3,106	3,135	3,186	3,208	3,241	3,276
PEPCO	6,524	6,563	6,581	6,605	6,625	6,638	6,675	6,720	6,739	6,791	6,838	6,908	7,004	7,117	7,222	7,342
PL	7,505	7,527	7,548	7,568	7,591	7,609	7,604	7,654	7,654	7,693	7,720	7,775	7,834	7,887	7,952	8,025
PS	10,879	11,043	11,077	11,128	11,223	11,371	11,507	11,663	11,746	11,927	12,133	12,342	12,556	12,828	12,941	13,204
RECO	466	468	466	464	461	459	459	461	463	466	470	474	483	485	492	498
UGI	212	212	212	212	212	212	212	213	214	215	216	217	219	221	223	225
DIVERSITY - MID-ATLANTIC(-)	1,199	1,263	1,164	1,084	1,053	1,040	1,060	1,176	1,199	1,254	1,327	1,426	1,150	1,214	1,295	1,492
PJM MID-ATLANTIC	60,435	60,697	60,973	61,241	61,579	61,950	62,352	62,843	63,220	63,815	64,519	65,353	66,644	67,652	68,452	69,413
FE-EAST	12,535	12,621	12,692	12,784	12,879	12,989	13,172	13,409	13,543	13,755	14,009	14,292	14,675	15,014	15,236	15,605
PLGRP	7,716	7,736	7,757	7,777	7,801	7,819	7,813	7,865	7,868	7,907	7,933	7,989	8,052	8,107	8,173	8,248

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, 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
2024 - 2039

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
AEP	24,034	24,974	25,718	26,225	26,625	26,884	27,044	27,197	27,312	27,439	27,570	27,724	27,885	28,121	28,282	28,534
APS	9,484	9,648	10,010	10,290	10,311	10,321	10,360	10,373	10,381	10,397	10,427	10,477	10,531	10,582	10,625	10,673
ATSI	13,345	13,332	13,338	13,342	13,358	13,364	13,370	13,375	13,386	13,431	13,483	13,535	13,618	13,702	13,785	13,887
COMED	22,673	22,653	22,629	22,691	22,527	22,496	22,488	22,495	22,577	22,593	22,664	22,795	22,942	23,093	23,162	23,341
DAYTON	3,582	3,586	3,592	3,602	3,604	3,620	3,623	3,625	3,625	3,637	3,658	3,679	3,697	3,719	3,741	3,768
DEOK	5,722	5,727	5,737	5,747	5,761	5,769	5,774	5,784	5,803	5,829	5,862	5,894	5,929	5,969	6,009	6,058
DLCO	2,908	2,912	2,922	2,938	2,956	2,973	2,988	3,006	3,026	3,048	3,081	3,106	3,143	3,178	3,215	3,262
EKPC	2,195	2,206	2,224	2,242	2,262	2,280	2,290	2,297	2,309	2,323	2,339	2,358	2,374	2,390	2,405	2,429
OVEC	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
DIVERSITY - WESTERN(-)	621	711	755	849	718	755	745	846	985	973	962	984	966	1,028	953	1,067
PJM WESTERN	83,412	84,417	85,505	86,318	86,776	87,042	87,282	87,396	87,524	87,814	88,212	88,674	89,243	89,816	90,361	90,975
DOM	24,144	25,057	26,829	28,695	31,033	33,042	34,758	36,211	37,586	38,949	40,274	41,540	42,780	44,030	45,311	46,647
DIVERSITY - TOTAL(-)	5,120	4,347	4,333	5,534	5,321	5,266	5,474	5,569	6,010	5,795	5,954	5,994	5,953	5,959	6,720	6,597
PJM RTO	164,691	167,798	170,893	172,653	175,838	178,563	180,723	182,903	184,504	187,010	189,340	191,983	194,830	197,781	199,652	202,997

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, 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
2023/24 - 2038/39

	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32	32/33	33/34	34/35	35/36	36/37	37/38	38/39
AE	1,702	1,745	1,802	1,858	1,919	1,970	2,029	2,083	2,154	2,204	2,265	2,332	2,414	2,473	2,539	2,606
BGE	6,410	6,409	6,429	6,450	6,492	6,503	6,509	6,541	6,600	6,608	6,646	6,731	6,874	6,928	7,011	7,121
DPL	4,084	4,061	4,072	4,089	4,142	4,131	4,148	4,168	4,217	4,206	4,233	4,270	4,311	4,347	4,390	4,422
JCPL	4,030	4,207	4,436	4,689	4,947	5,203	5,444	5,686	5,944	6,167	6,397	6,651	6,897	7,127	7,366	7,621
METED	2,897	2,903	2,951	3,015	3,086	3,150	3,212	3,276	3,351	3,431	3,516	3,615	3,727	3,835	3,947	4,063
PECO	6,921	6,896	6,918	6,963	7,032	7,065	7,092	7,123	7,179	7,220	7,271	7,350	7,425	7,460	7,535	7,611
PENLC	2,985	2,959	2,955	2,957	2,978	2,966	2,962	2,969	2,995	2,995	3,004	3,021	3,059	3,053	3,071	3,092
PEPCO	5,803	5,807	5,838	5,866	5,916	5,910	5,934	5,973	6,026	6,059	6,110	6,171	6,259	6,294	6,339	6,395
PL	7,709	7,714	7,726	7,744	7,755	7,754	7,765	7,772	7,777	7,787	7,799	7,818	7,856	7,899	7,926	7,959
PS	7,137	7,403	7,716	8,099	8,502	8,867	9,221	9,550	9,934	10,222	10,493	10,813	11,140	11,412	11,722	12,051
RECO	236	242	251	260	270	280	288	298	307	316	324	334	342	351	359	368
UGI	212	211	211	212	212	213	213	213	214	214	215	216	217	218	220	221
DIVERSITY - MID-ATLANTIC(-)	1,389	1,315	1,237	1,239	1,189	1,178	1,026	942	927	833	774	692	724	759	735	766
PJM MID-ATLANTIC	48,737	49,242	50,068	50,963	52,062	52,834	53,791	54,710	55,771	56,596	57,499	58,630	59,797	60,638	61,690	62,764
FE-EAST	9,791	9,969	10,255	10,583	10,956	11,247	11,561	11,868	12,247	12,537	12,873	13,240	13,655	13,911	14,308	14,693
PLGRP	7,911	7,916	7,931	7,945	7,957	7,957	7,965	7,973	7,983	7,989	8,008	8,031	8,073	8,106	8,137	8,176

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, 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
2024 - 2039

	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32	32/33	33/34	34/35	35/36	36/37	37/38	38/39
AEP	24,716	25,401	26,092	26,612	27,344	27,274	27,472	27,527	27,814	27,652	27,775	27,882	28,095	28,005	28,196	28,340
APS	9,952	10,126	10,172	10,640	10,921	10,923	10,948	10,978	11,057	11,037	11,046	11,076	11,135	11,129	11,182	11,197
ATSI	10,840	10,732	10,761	10,802	10,945	10,906	10,926	10,942	11,005	10,991	11,028	11,096	11,167	11,163	11,210	11,289
COMED	15,639	15,656	15,730	15,836	15,947	15,999	16,076	16,149	16,308	16,367	16,489	16,641	16,837	16,896	17,040	17,210
DAYTON	3,108	3,099	3,098	3,100	3,119	3,113	3,110	3,103	3,106	3,104	3,104	3,110	3,123	3,133	3,142	3,150
DEOK	4,885	4,855	4,861	4,873	4,911	4,901	4,899	4,893	4,924	4,930	4,947	4,974	4,963	4,960	4,980	5,039
DLCO	2,106	2,084	2,092	2,106	2,141	2,142	2,154	2,164	2,196	2,204	2,224	2,251	2,286	2,297	2,324	2,351
EKPC	3,114	3,090	3,132	3,157	3,164	3,171	3,158	3,154	3,185	3,190	3,201	3,202	3,193	3,226	3,247	3,250
OVEC	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110
DIVERSITY - WESTERN(-)	2,109	2,171	2,280	2,301	2,510	2,305	2,374	2,404	2,582	2,687	2,795	2,421	2,249	2,513	2,641	2,461
PJM WESTERN	72,361	72,982	73,768	74,935	76,092	76,234	76,479	76,616	77,123	76,898	77,129	77,921	78,660	78,406	78,790	79,475
DOM	24,826	25,476	26,999	28,667	30,641	32,461	34,136	35,584	36,823	37,974	39,053	40,165	41,240	42,094	43,246	44,353
DIVERSITY - TOTAL(-)	6,349	5,927	6,257	6,511	7,476	7,121	6,938	6,592	6,891	6,409	6,298	6,178	6,314	5,698	5,896	5,987
PJM RTO	143,073	145,259	148,095	151,594	155,018	157,891	160,868	163,664	166,335	168,579	170,952	173,651	176,356	178,712	181,206	183,832

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, 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 2024 - 2034

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Annual Growth Rate (10 yr)
AE	9,956	9,970	10,026	10,077	10,170	10,228	10,321	10,438	10,621	10,759	10,972	1.0%
		0.1%	0.6%	0.5%	0.9%	0.6%	0.9%	1.1%	1.8%	1.3%	2.0%	
BGE	30,725	30,767	30,940	31,149	31,489	31,684	31,975	32,330	32,851	33,147	33,650	0.9%
		0.1%	0.6%	0.7%	1.1%	0.6%	0.9%	1.1%	1.6%	0.9%	1.5%	
DPL	18,330	18,163	18,121	18,115	18,189	18,137	18,138	18,188	18,357	18,386	18,535	0.1%
		-0.9%	-0.2%	-0.0%	0.4%	-0.3%	0.0%	0.3%	0.9%	0.2%	0.8%	
JCPL	22,673	23,004	23,443	23,894	24,451	24,935	25,514	26,176	27,017	27,708	28,609	2.4%
		1.5%	1.9%	1.9%	2.3%	2.0%	2.3%	2.6%	3.2%	2.6%	3.3%	
METED	16,123	16,338	16,755	17,211	17,729	18,132	18,585	19,093	19,744	20,252	20,946	2.7%
		1.3%	2.6%	2.7%	3.0%	2.3%	2.5%	2.7%	3.4%	2.6%	3.4%	
PECO	39,070	39,011	39,209	39,435	39,814	39,880	40,102	40,391	40,889	41,043	41,433	0.6%
		-0.2%	0.5%	0.6%	1.0%	0.2%	0.6%	0.7%	1.2%	0.4%	1.0%	
PENLC	17,334	17,250	17,287	17,336	17,449	17,421	17,463	17,532	17,695	17,703	17,812	0.3%
		-0.5%	0.2%	0.3%	0.7%	-0.2%	0.2%	0.4%	0.9%	0.0%	0.6%	
PEPCO	28,588	28,656	28,822	28,995	29,268	29,399	29,595	29,832	30,183	30,341	30,663	0.7%
		0.2%	0.6%	0.6%	0.9%	0.4%	0.7%	0.8%	1.2%	0.5%	1.1%	
PL	40,546	40,455	40,599	40,754	41,047	41,028	41,136	41,290	41,640	41,629	41,842	0.3%
		-0.2%	0.4%	0.4%	0.7%	-0.0%	0.3%	0.4%	0.8%	-0.0%	0.5%	
PS	43,445	44,025	44,717	45,483	46,395	47,172	47,995	48,716	49,776	50,545	51,645	1.7%
		1.3%	1.6%	1.7%	2.0%	1.7%	1.7%	1.5%	2.2%	1.5%	2.2%	
RECO	1,464	1,474	1,487	1,498	1,513	1,526	1,539	1,557	1,583	1,601	1,628	1.1%
		0.7%	0.9%	0.7%	1.0%	0.9%	0.9%	1.2%	1.7%	1.1%	1.7%	
UGI	1,056	1,051	1,054	1,058	1,063	1,063	1,065	1,068	1,078	1,078	1,088	0.3%
		-0.5%	0.3%	0.4%	0.5%	0.0%	0.2%	0.3%	0.9%	0.0%	0.9%	
PJM MID-ATLANTIC	269,310	270,164	272,460	275,005	278,577	280,605	283,428	286,611	291,434	294,192	298,823	1.0%
		0.3%	0.8%	0.9%	1.3%	0.7%	1.0%	1.1%	1.7%	0.9%	1.6%	
FE-EAST	56,130	56,592	57,485	58,441	59,629	60,488	61,562	62,801	64,456	65,663	67,367	1.8%
		0.8%	1.6%	1.7%	2.0%	1.4%	1.8%	2.0%	2.6%	1.9%	2.6%	
PLGRP	41,602	41,506	41,653	41,812	42,110	42,091	42,201	42,358	42,718	42,707	42,930	0.3%
		-0.2%	0.4%	0.4%	0.7%	-0.0%	0.3%	0.4%	0.8%	-0.0%	0.5%	

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation, and additions for plug-in electric vehicles.
All average growth rates are calculated from the first year of the forecast (2024).

Table E-1 (continued)

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION 2035 - 2039

	2035	2036	2037	2038	2039	Annual Growth Rate (15 yr)
AE	11,233	11,551	11,796	12,082	12,412	1.5%
	2.4%	2.8%	2.1%	2.4%	2.7%	
BGE	34,260	35,078	35,652	36,350	37,184	1.3%
	1.8%	2.4%	1.6%	2.0%	2.3%	
DPL	18,739	19,071	19,258	19,513	19,809	0.5%
	1.1%	1.8%	1.0%	1.3%	1.5%	
JCPL	29,656	30,816	31,783	32,851	34,053	2.7%
	3.7%	3.9%	3.1%	3.4%	3.7%	
METED	21,763	22,716	23,513	24,433	25,435	3.1%
	3.9%	4.4%	3.5%	3.9%	4.1%	
PECO	41,905	42,594	42,912	43,426	43,989	0.8%
	1.1%	1.6%	0.7%	1.2%	1.3%	
PENLC	17,959	18,206	18,300	18,474	18,670	0.5%
	0.8%	1.4%	0.5%	1.0%	1.1%	
PEPCO	31,070	31,641	32,026	32,507	33,057	1.0%
	1.3%	1.8%	1.2%	1.5%	1.7%	
PL	42,089	42,597	42,758	43,094	43,453	0.5%
	0.6%	1.2%	0.4%	0.8%	0.8%	
PS	52,948	54,485	55,675	57,071	58,600	2.0%
	2.5%	2.9%	2.2%	2.5%	2.7%	
RECO	1,659	1,702	1,732	1,765	1,805	1.4%
	1.9%	2.6%	1.8%	1.9%	2.3%	
UGI	1,097	1,114	1,122	1,134	1,150	0.6%
	0.8%	1.5%	0.7%	1.1%	1.4%	
PJM MID-ATLANTIC	304,378	311,571	316,527	322,700	329,617	1.4%
	1.9%	2.4%	1.6%	2.0%	2.1%	
FE-EAST	69,378	71,738	73,596	75,758	78,158	2.2%
	3.0%	3.4%	2.6%	2.9%	3.2%	
PLGRP	43,186	43,711	43,880	44,228	44,603	0.5%
	0.6%	1.2%	0.4%	0.8%	0.8%	

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation, and additions for plug-in electric vehicles.
All average growth rates are calculated from the first year of the forecast (2024).

Table E-1

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO 2024 - 2034

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Annual Growth Rate (10 yr)
AEP	135,995	144,174	150,566	155,236	159,451	161,012	162,521	163,854	165,268	165,289	166,117	2.0%
		6.0%	4.4%	3.1%	2.7%	1.0%	0.9%	0.8%	0.9%	0.0%	0.5%	
APS	51,299	52,290	54,687	57,259	58,493	58,518	58,702	58,872	59,294	59,181	59,383	1.5%
		1.9%	4.6%	4.7%	2.2%	0.0%	0.3%	0.3%	0.7%	-0.2%	0.3%	
ATSI	66,125	65,898	66,102	66,403	66,955	66,947	67,092	67,284	67,821	67,755	68,088	0.3%
		-0.3%	0.3%	0.5%	0.8%	-0.0%	0.2%	0.3%	0.8%	-0.1%	0.5%	
COMED	93,350	93,118	93,408	93,740	94,361	94,331	94,557	94,965	95,889	96,098	96,887	0.4%
		-0.2%	0.3%	0.4%	0.7%	-0.0%	0.2%	0.4%	1.0%	0.2%	0.8%	
DAYTON	17,224	17,202	17,263	17,335	17,456	17,443	17,461	17,497	17,624	17,601	17,677	0.3%
		-0.1%	0.4%	0.4%	0.7%	-0.1%	0.1%	0.2%	0.7%	-0.1%	0.4%	
DEOK	27,125	27,062	27,144	27,230	27,408	27,400	27,460	27,554	27,778	27,799	27,955	0.3%
		-0.2%	0.3%	0.3%	0.7%	-0.0%	0.2%	0.3%	0.8%	0.1%	0.6%	
DLCO	13,197	13,153	13,211	13,286	13,417	13,461	13,539	13,644	13,817	13,892	14,047	0.6%
		-0.3%	0.4%	0.6%	1.0%	0.3%	0.6%	0.8%	1.3%	0.5%	1.1%	
EKPC	11,431	11,497	11,654	11,820	12,014	12,089	12,192	12,291	12,458	12,512	12,633	1.0%
		0.6%	1.4%	1.4%	1.6%	0.6%	0.9%	0.8%	1.4%	0.4%	1.0%	
OVEC	325	325	325	325	325	325	325	325	325	325	325	0.0%
		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
PJM WESTERN	416,071	424,719	434,360	442,634	449,880	451,526	453,849	456,286	460,274	460,452	463,112	1.1%
		2.1%	2.3%	1.9%	1.6%	0.4%	0.5%	0.5%	0.9%	0.0%	0.6%	
DOM	127,947	134,800	150,124	165,597	185,010	201,015	215,301	227,376	239,480	249,565	260,020	7.3%
		5.4%	11.4%	10.3%	11.7%	8.7%	7.1%	5.6%	5.3%	4.2%	4.2%	
PJM RTO	813,328	829,683	856,944	883,236	913,467	933,146	952,578	970,273	991,188	1,004,209	1,021,955	2.3%
		2.0%	3.3%	3.1%	3.4%	2.2%	2.1%	1.9%	2.2%	1.3%	1.8%	

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation, and additions for plug-in electric vehicles.
All average growth rates are calculated from the first year of the forecast (2024).

Table E-1 (Continued)

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO 2024 - 2034

	2035	2036	2037	2038	2039	Annual Growth Rate (15 yr)
AEP	167,252	169,070	169,532	170,725	171,991	1.6%
	0.7%	1.1%	0.3%	0.7%	0.7%	
APS	59,744	60,336	60,387	60,691	61,039	1.2%
	0.6%	1.0%	0.1%	0.5%	0.6%	
ATSI	68,563	69,359	69,552	70,096	70,668	0.4%
	0.7%	1.2%	0.3%	0.8%	0.8%	
COMED	98,043	99,584	100,336	101,528	102,896	0.7%
	1.2%	1.6%	0.8%	1.2%	1.3%	
DAYTON	17,801	18,008	18,064	18,201	18,350	0.4%
	0.7%	1.2%	0.3%	0.8%	0.8%	
DEOK	28,187	28,522	28,640	28,877	29,131	0.5%
	0.8%	1.2%	0.4%	0.8%	0.9%	
DLCO	14,240	14,502	14,665	14,878	15,119	0.9%
	1.4%	1.8%	1.1%	1.5%	1.6%	
EKPC	12,782	12,988	13,072	13,221	13,375	1.1%
	1.2%	1.6%	0.6%	1.1%	1.2%	
OVEC	325	325	325	325	325	0.0%
	0.0%	0.0%	0.0%	0.0%	0.0%	
PJM WESTERN	466,937	472,694	474,573	478,542	482,894	1.0%
	0.8%	1.2%	0.4%	0.8%	0.9%	
DOM	269,902	280,018	288,582	298,296	308,417	6.0%
	3.8%	3.7%	3.1%	3.4%	3.4%	
PJM RTO	1,041,217	1,064,283	1,079,682	1,099,538	1,120,928	2.2%
	1.9%	2.2%	1.4%	1.8%	1.9%	

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation, and additions for plug-in electric vehicles.
All average growth rates are calculated from the first year of the forecast (2024).

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 2024	862	3,005	1,850	2,013	1,537	3,603	1,657	2,749	4,055	3,799	122	109	25,361
Feb 2024	772	2,674	1,637	1,812	1,407	3,282	1,539	2,451	3,678	3,459	110	100	22,921
Mar 2024	732	2,474	1,507	1,725	1,326	3,114	1,492	2,254	3,469	3,347	107	94	21,641
Apr 2024	643	2,093	1,227	1,526	1,174	2,731	1,318	1,943	2,965	3,002	99	76	18,797
May 2024	726	2,241	1,296	1,664	1,208	2,912	1,322	2,120	2,987	3,235	115	75	19,901
Jun 2024	882	2,598	1,510	1,996	1,322	3,362	1,370	2,454	3,184	3,811	136	80	22,705
Jul 2024	1,161	3,072	1,854	2,468	1,514	3,996	1,531	2,907	3,683	4,581	163	95	27,025
Aug 2024	1,099	2,949	1,760	2,349	1,491	3,855	1,491	2,780	3,551	4,415	154	89	25,983
Sep 2024	832	2,393	1,398	1,827	1,240	3,121	1,315	2,270	3,030	3,580	123	75	21,204
Oct 2024	701	2,175	1,261	1,636	1,214	2,814	1,358	2,045	3,009	3,249	108	77	19,647
Nov 2024	711	2,288	1,353	1,669	1,242	2,887	1,383	2,112	3,203	3,238	106	84	20,276
Dec 2024	835	2,763	1,677	1,988	1,448	3,393	1,558	2,503	3,732	3,729	121	102	23,849

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	MID-ATLANTIC
Jan 2025	874	3,021	1,851	2,080	1,555	3,610	1,653	2,768	4,059	3,905	125	109	25,610
Feb 2025	744	2,571	1,557	1,779	1,346	3,107	1,450	2,366	3,498	3,382	107	94	22,001
Mar 2025	739	2,490	1,502	1,771	1,350	3,128	1,496	2,274	3,483	3,430	108	94	21,865
Apr 2025	645	2,102	1,217	1,553	1,192	2,737	1,315	1,953	2,965	3,044	100	76	18,899
May 2025	725	2,245	1,278	1,678	1,224	2,910	1,315	2,124	2,979	3,260	115	74	19,927
Jun 2025	881	2,612	1,497	2,014	1,349	3,378	1,375	2,471	3,200	3,854	137	81	22,849
Jul 2025	1,159	3,085	1,839	2,487	1,546	4,012	1,536	2,923	3,701	4,630	164	95	27,177
Aug 2025	1,097	2,954	1,745	2,361	1,509	3,855	1,484	2,786	3,543	4,444	154	89	26,021
Sep 2025	834	2,410	1,390	1,852	1,273	3,141	1,323	2,289	3,052	3,637	124	76	21,401
Oct 2025	705	2,188	1,255	1,663	1,242	2,823	1,357	2,055	3,015	3,299	109	77	19,788
Nov 2025	717	2,300	1,349	1,705	1,265	2,892	1,379	2,120	3,201	3,292	107	84	20,411
Dec 2025	850	2,789	1,683	2,061	1,487	3,418	1,567	2,527	3,759	3,848	124	102	24,215

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	MID-ATLANTIC
Jan 2026	887	3,033	1,853	2,149	1,582	3,617	1,648	2,781	4,060	4,011	127	109	25,857
Feb 2026	756	2,586	1,558	1,840	1,376	3,120	1,452	2,382	3,509	3,475	109	95	22,258
Mar 2026	748	2,508	1,501	1,825	1,388	3,152	1,504	2,295	3,506	3,515	110	94	22,146
Apr 2026	648	2,113	1,208	1,581	1,224	2,750	1,317	1,962	2,975	3,084	101	76	19,039
May 2026	724	2,250	1,264	1,690	1,250	2,915	1,310	2,126	2,975	3,276	115	74	19,969
Jun 2026	880	2,625	1,487	2,029	1,390	3,401	1,384	2,486	3,223	3,892	137	81	23,015
Jul 2026	1,156	3,095	1,829	2,499	1,582	4,029	1,539	2,935	3,713	4,656	164	95	27,292
Aug 2026	1,095	2,968	1,738	2,380	1,547	3,877	1,491	2,802	3,559	4,483	155	89	26,184
Sep 2026	835	2,423	1,387	1,871	1,308	3,157	1,326	2,302	3,062	3,669	124	76	21,540
Oct 2026	707	2,199	1,250	1,688	1,273	2,832	1,355	2,061	3,015	3,333	110	77	19,900
Nov 2026	726	2,326	1,354	1,756	1,307	2,919	1,388	2,143	3,225	3,368	109	85	20,706
Dec 2026	864	2,814	1,692	2,135	1,528	3,440	1,573	2,547	3,777	3,955	126	103	24,554

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation, and additions for plug-in electric vehicles.

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	OVEC	PJM WESTERN	DOM	PJM RTO
Jan 2024	13,028	5,059	6,120	8,450	1,630	2,504	1,176	1,251	30	39,248	11,771	76,380
Feb 2024	11,819	4,590	5,676	7,800	1,483	2,259	1,078	1,079	30	35,814	10,552	69,287
Mar 2024	11,265	4,277	5,520	7,437	1,400	2,138	1,044	953	25	34,059	9,986	65,686
Apr 2024	10,055	3,697	4,932	6,758	1,241	1,932	951	783	25	30,374	8,945	58,116
May 2024	10,400	3,792	5,102	7,117	1,307	2,105	1,030	813	25	31,691	9,735	61,327
Jun 2024	11,159	4,057	5,557	8,201	1,447	2,386	1,168	901	25	34,901	10,747	68,353
Jul 2024	12,263	4,530	6,159	9,346	1,600	2,653	1,324	1,002	30	38,907	12,264	78,196
Aug 2024	12,131	4,483	6,031	8,962	1,599	2,611	1,279	983	30	38,109	11,996	76,088
Sep 2024	10,562	3,905	5,133	7,492	1,350	2,182	1,062	823	25	32,534	10,358	64,096
Oct 2024	10,389	3,938	5,052	6,948	1,307	1,994	982	800	20	31,430	9,788	60,865
Nov 2024	10,721	4,125	5,097	6,957	1,341	2,020	989	911	25	32,186	10,124	62,586
Dec 2024	12,203	4,846	5,746	7,882	1,519	2,341	1,114	1,132	35	36,818	11,681	72,348

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	OVEC	WESTERN	DOM	PJM RTO
Jan 2025	13,758	5,219	6,104	8,460	1,629	2,506	1,174	1,256	30	40,136	12,286	78,032
Feb 2025	11,873	4,490	5,346	7,397	1,404	2,150	1,022	1,030	30	34,742	10,565	67,308
Mar 2025	12,033	4,446	5,525	7,455	1,406	2,145	1,045	962	25	35,042	10,547	67,454
Apr 2025	10,758	3,842	4,923	6,757	1,241	1,932	950	791	25	31,219	9,482	59,600
May 2025	11,105	3,922	5,081	7,090	1,303	2,100	1,026	820	25	32,472	10,304	62,703
Jun 2025	11,894	4,193	5,570	8,212	1,456	2,392	1,170	911	25	35,823	11,360	70,032
Jul 2025	13,028	4,665	6,183	9,367	1,610	2,661	1,327	1,015	30	39,886	12,918	79,981
Aug 2025	12,825	4,569	6,011	8,923	1,596	2,606	1,276	992	30	38,828	12,629	77,478
Sep 2025	11,329	3,954	5,175	7,546	1,365	2,195	1,067	837	25	33,493	11,024	65,918
Oct 2025	11,135	3,938	5,075	6,981	1,314	1,998	985	812	20	32,258	10,463	62,509
Nov 2025	11,425	4,149	5,103	6,964	1,342	2,020	990	923	25	32,941	10,787	64,139
Dec 2025	13,011	4,903	5,802	7,966	1,536	2,357	1,121	1,148	35	37,879	12,435	74,529

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	OVEC	WESTERN	DOM	PJM RTO
Jan 2026	14,271	5,232	6,097	8,463	1,627	2,507	1,175	1,267	30	40,669	13,320	79,846
Feb 2026	12,364	4,510	5,358	7,423	1,408	2,157	1,025	1,042	30	35,317	11,556	69,131
Mar 2026	12,609	4,533	5,560	7,506	1,417	2,158	1,051	977	25	35,836	11,688	69,670
Apr 2026	11,278	3,933	4,938	6,778	1,246	1,938	954	804	25	31,894	10,587	61,520
May 2026	11,605	4,039	5,073	7,071	1,300	2,098	1,026	831	25	33,068	11,497	64,534
Jun 2026	12,446	4,458	5,605	8,249	1,468	2,404	1,177	926	25	36,758	12,624	72,397
Jul 2026	13,567	4,925	6,198	9,376	1,615	2,666	1,333	1,027	30	40,737	14,275	82,304
Aug 2026	13,374	4,881	6,032	8,942	1,603	2,615	1,282	1,006	30	39,765	14,040	79,989
Sep 2026	11,846	4,252	5,188	7,563	1,368	2,200	1,073	849	25	34,364	12,418	68,322
Oct 2026	11,647	4,236	5,077	6,988	1,313	1,999	988	824	20	33,092	11,896	64,888
Nov 2026	11,987	4,464	5,143	7,029	1,354	2,034	998	938	25	33,972	12,259	66,937
Dec 2026	13,572	5,224	5,833	8,020	1,544	2,368	1,129	1,163	35	38,888	13,964	77,406

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation, and additions for plug-in electric vehicles.

Table E-3

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

	FE_EAST	PLGRP
Jan 2024	5,207	4,164
Feb 2024	4,758	3,778
Mar 2024	4,543	3,563
Apr 2024	4,018	3,041
May 2024	4,194	3,062
Jun 2024	4,688	3,264
Jul 2024	5,513	3,778
Aug 2024	5,331	3,640
Sep 2024	4,382	3,105
Oct 2024	4,208	3,086
Nov 2024	4,294	3,287
Dec 2024	4,994	3,834

	FE_EAST	PLGRP
Jan 2025	5,288	4,168
Feb 2025	4,575	3,592
Mar 2025	4,617	3,577
Apr 2025	4,060	3,041
May 2025	4,217	3,053
Jun 2025	4,738	3,281
Jul 2025	5,569	3,796
Aug 2025	5,354	3,632
Sep 2025	4,448	3,128
Oct 2025	4,262	3,092
Nov 2025	4,349	3,285
Dec 2025	5,115	3,861

	FE_EAST	PLGRP
Jan 2026	5,379	4,169
Feb 2026	4,668	3,604
Mar 2026	4,717	3,600
Apr 2026	4,122	3,051
May 2026	4,250	3,049
Jun 2026	4,803	3,304
Jul 2026	5,620	3,808
Aug 2026	5,418	3,648
Sep 2026	4,505	3,138
Oct 2026	4,316	3,092
Nov 2026	4,451	3,310
Dec 2026	5,236	3,880

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation, and additions for plug-in electric vehicles.

Table E-4

PLUG IN ELECTRIC VEHICLE ADJUSTMENT TO ANNUAL ENERGY (GWh) FOR EACH PJM ZONE AND RTO
2024 - 2039

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
AE	52	129	237	357	487	635	797	989	1,202	1,423	1,680	1,963	2,251	2,533	2,816	3,148
BGE	168	370	646	950	1,284	1,684	2,126	2,652	3,242	3,860	4,565	5,339	6,132	6,910	7,692	8,599
DPL	53	130	234	347	470	612	762	947	1,158	1,381	1,635	1,917	2,207	2,493	2,780	3,114
JCPL	238	506	876	1,289	1,730	2,228	2,750	3,374	4,088	4,829	5,671	6,588	7,512	8,413	9,315	10,376
METED	96	233	424	637	866	1,140	1,427	1,782	2,198	2,638	3,166	3,784	4,453	5,144	5,868	6,686
PECO	119	247	420	611	815	1,046	1,295	1,596	1,939	2,298	2,704	3,149	3,606	4,056	4,512	5,042
PENLC	32	84	155	232	314	406	505	627	766	912	1,081	1,270	1,466	1,661	1,859	2,087
PEPCO	124	247	410	589	784	1,011	1,262	1,561	1,897	2,249	2,648	3,084	3,533	3,992	4,443	4,962
PL	54	125	223	329	443	574	715	887	1,083	1,288	1,525	1,788	2,063	2,337	2,617	2,938
PS	266	572	997	1,473	1,981	2,562	3,199	3,951	4,785	5,652	6,644	7,731	8,836	9,918	11,007	12,281
RECO	11	21	33	47	62	79	97	119	142	167	194	224	254	283	312	346
UGI	3	7	12	17	23	30	38	47	57	68	80	94	109	123	138	155
AEP	134	331	602	900	1,223	1,605	2,028	2,547	3,140	3,770	4,508	5,352	6,250	7,157	8,093	9,154
APS	51	123	219	325	438	571	716	892	1,093	1,304	1,547	1,816	2,095	2,371	2,651	2,973
ATSI	123	284	503	742	996	1,286	1,599	1,981	2,420	2,884	3,425	4,040	4,686	5,330	5,990	6,743
COMED	362	784	1,346	1,962	2,614	3,345	4,128	5,070	6,142	7,273	8,559	9,987	11,478	12,950	14,447	16,180
DAYTON	21	53	97	144	194	251	314	390	480	576	690	824	967	1,112	1,261	1,431
DEOK	52	110	188	274	367	474	589	729	890	1,059	1,255	1,476	1,709	1,942	2,180	2,452
DLCO	48	109	192	283	379	489	606	750	916	1,090	1,290	1,513	1,744	1,973	2,207	2,475
EKPC	13	32	59	88	119	155	193	241	297	358	427	506	591	675	762	860
OVEC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DOM	312	683	1,181	1,726	2,314	2,980	3,691	4,564	5,566	6,627	7,814	9,110	10,444	11,748	13,054	14,578
PJM RTO	2,333	5,179	9,056	13,324	17,903	23,163	28,836	35,695	43,503	51,709	61,108	71,555	82,382	93,120	104,003	116,579

Notes:
Adjustment values presented here are reflected in all energy forecast values.

Values are derived by PJM from a forecast obtained from SPGCI.

Table F-1

PJM RTO HISTORICAL PEAKS
(MW)

SUMMER

YEAR	NORMALIZED TOTAL	UNRESTRICTED PEAK	PEAK DATE	TIME
1998		133,275	Tuesday, July 21, 1998	17:00
1999		141,491	Friday, July 30, 1999	17:00
2000		131,798	Wednesday, August 9, 2000	17:00
2001		150,924	Thursday, August 9, 2001	16:00
2002		150,826	Thursday, August 1, 2002	17:00
2003		145,227	Thursday, August 21, 2003	17:00
2004		139,279	Tuesday, August 3, 2004	17:00
2005		155,257	Tuesday, July 26, 2005	16:00
2006		166,929	Wednesday, August 2, 2006	17:00
2007		162,035	Wednesday, August 8, 2007	16:00
2008		150,622	Monday, June 9, 2008	17:00
2009		145,112	Monday, August 10, 2009	16:00
2010		157,247	Wednesday, July 7, 2010	17:00
2011		165,524	Thursday, July 21, 2011	17:00
2012		158,219	Tuesday, July 17, 2012	17:00
2013		159,149	Thursday, July 18, 2013	17:00
2014	150,051	141,509	Tuesday, June 17, 2014	18:00
2015	149,806	143,579	Tuesday, July 28, 2015	17:00
2016	149,213	152,069	Thursday, August 11, 2016	16:00
2017	148,948	145,434	Wednesday, July 19, 2017	18:00
2018	149,360	150,573	Tuesday, August 28, 2018	17:00
2019	149,259	151,302	Friday, July 19, 2019	18:00
2020	147,060	144,320	Monday, July 20, 2020	17:00
2021	149,780	148,433	Tuesday, August 24, 2021	18:00
2022	150,123	147,361	Wednesday, July 20, 2022	18:00
2023	149,884	146,799	Thursday, July 27, 2023	18:00

Notes:
Normalized values for 2014 - 2023 are calculated by PJM staff using a methodology described in Manual 19.
All times are shown in hour ending Eastern Prevailing Time and historic peak values reflect current membership of the PJM RTO.

Table F-1

PJM RTO HISTORICAL PEAKS
(MW)

WINTER

YEAR	NORMALIZED TOTAL	UNRESTRICTED PEAK	PEAK DATE	TIME
97/98		103,231	Wednesday, January 14, 1998	19:00
98/99		116,086	Tuesday, January 5, 1999	19:00
99/00		118,435	Thursday, January 27, 2000	20:00
00/01		118,046	Wednesday, December 20, 2000	19:00
01/02		112,217	Wednesday, January 2, 2002	19:00
02/03		129,965	Thursday, January 23, 2003	19:00
03/04		122,424	Friday, January 23, 2004	9:00
04/05		131,234	Monday, December 20, 2004	19:00
05/06		126,777	Wednesday, December 14, 2005	19:00
06/07		136,804	Monday, February 5, 2007	20:00
07/08		128,368	Wednesday, January 2, 2008	19:00
08/09		134,077	Friday, January 16, 2009	19:00
09/10		125,350	Monday, January 4, 2010	19:00
10/11		132,315	Tuesday, December 14, 2010	19:00
11/12		124,506	Tuesday, January 3, 2012	19:00
12/13		128,810	Tuesday, January 22, 2013	19:00
13/14		141,866	Tuesday, January 7, 2014	19:00
14/15	130,759	142,856	Friday, February 20, 2015	8:00
15/16	131,217	129,540	Tuesday, January 19, 2016	8:00
16/17	130,755	130,825	Thursday, December 15, 2016	19:00
17/18	131,191	137,212	Friday, January 5, 2018	19:00
18/19	130,605	137,618	Thursday, January 31, 2019	8:00
19/20	131,223	120,272	Thursday, December 19, 2019	8:00
20/21	130,059	117,012	Friday, January 29, 2021	9:00
21/22	132,636	128,882	Thursday, January 27, 2022	8:00
22/23	133,059	134,951	Friday, December 23, 2022	19:00

Notes:
Normalized values for 2014/15 - 2022/23 are calculated by PJM staff using a methodology described in Manual 19.
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	718,248	0.0%
1999	740,056	3.0%
2000	756,211	2.2%
2001	754,516	-0.2%
2002	782,275	3.7%
2003	780,666	-0.2%
2004	796,702	2.1%
2005	823,342	3.3%
2006	802,984	-2.5%
2007	836,241	4.1%
2008	822,608	-1.6%
2009	781,270	-5.0%
2010	820,038	5.0%
2011	805,911	-1.7%
2012	791,768	-1.8%
2013	795,098	0.4%
2014	796,228	0.1%
2015	791,580	-0.6%
2016	791,176	-0.1%
2017	772,291	-2.4%
2018	804,917	4.2%
2019	785,209	-2.4%
2020	755,241	-3.8%
2021	780,454	3.3%
2022	792,832	1.6%

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

Table F-3

WEATHER NORMALIZED LOAD (MW) FOR
EACH PJM ZONE, LOCATIONAL DELIVERABILITY AREA AND RTO

	Summer 2023	Winter 2022/23
AE	2,601	1,616
BGE	6,502	5,820
DPL	3,964	3,700
JCPL	6,067	3,788
METED	3,026	2,745
PECO	8,593	6,577
PENLC	2,876	2,831
PEPCO	6,035	5,327
PL	7,129	7,366
PS	10,069	6,783
RECO	412	224
UGI	198	202
AEP	22,332	22,423
APS	8,742	9,176
ATSI	12,508	10,411
COMED	20,639	14,787
DAYTON	3,312	2,943
DEOK	5,360	4,636
DLCO	2,713	2,013
EKPC	2,084	2,745
OVEC	90	110
DOM	21,804	21,791
PJM MID-ATLANTIC	55,976	46,300
PJM WESTERN	76,115	67,192
PJM RTO	149,884	133,059

Notes:
Zonal Normal 2023 are non-coincident as estimated by PJM staff.
Locational Deliverability Area and PJM RTO Normal 2023 are coincident with their regional peak as estimated by PJM staff.

EXHIBIT NO. 50



2025

PJM Long-Term Load Forecast Report

Posted Date: January 24, 2025

Prepared by PJM Resource Adequacy Planning Department

For Public Use

Contents

TO Zones and Subzones 1
Glossary 3
Executive Summary 4
Energy Information Administration & Vendor Data 5
Load Adjustments 5
Summer & Winter Summary 6
PJM Map 7
PJM RTO, LDA, and Zonal Dashboards 8

TO Zones and Subzones

Abbreviation	Zone Name	Date Incorporated
AE	Atlantic Electric zone	
AEP	American Electric Power zone	Oct. 1, 2004
APP	Appalachian Power, sub-zone of AEP	
APS	Allegheny Power zone	April 1, 2002
ATSI	American Transmission Systems, Inc. zone	June 1, 2011
BGE	Baltimore Gas & Electric zone	
CEI	Cleveland Electric Illuminating, sub-zone of ATSI	
COMED	Commonwealth Edison zone	May 1, 2004
CSP	Columbus Southern Power, sub-zone of AEP	
DAY	Dayton Power & Light zone	Oct. 1, 2004
DEOK	Duke Energy Ohio/Kentucky zone	January 1, 2012
DLCO	Duquesne Lighting Company zone	January 1, 2005
DOM	Dominion Virginia Power zone	May 1, 2005
DPL	Delmarva Power & Light zone	
EKPC	East Kentucky Power Cooperative zone	June 1, 2013
FE-East	The combination of FirstEnergy's Jersey Central Power & Light, Metropolitan Edison, and Pennsylvania Electric zones (formerly GPU)	
INM	Indiana Michigan Power, sub-zone of AEP	
JCP&L	Jersey Central Power & Light zone	
KP	Kentucky Power, sub-zone of AEP	

Abbreviation	Zone Name	Date Incorporated
METED	Metropolitan Edison zone	
MP	Monongahela Power, sub-zone of APS	
OEP	Ohio Edison, sub-zone of ATSI	
OP	Ohio Power, sub-zone of AEP	
OVEC	Ohio Valley Electric Corporation zone	December 1, 2018
PECO	PECO Energy zone	
PED	Potomac Edison, sub-zone of APS	
PEPCO	Potomac Electric Power zone	
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	March 1, 2002
TOL	Toledo Edison, sub-zone of ATSI	
UGI	UGI Utilities, sub-zone of PLGroup	
WP	West Penn Power, sub-zone of APS	

Glossary

Term / Abbreviation	Definition
Battery Storage	Devices that enable generated energy to be stored and then released at a later time. (Also Battery Energy Storage System – BESS)
Contractually Interruptible	Load Management from customers responding to direction from a control center
Cooling Load	The weather-sensitive portion of summer peak load
Direct Control	Load Management achieved directly by a signal from a control center
Heating Load	The weather-sensitive portion of winter peak load
Net Energy	Net Energy for Load, measured as net generation of main generating units plus energy receipts minus energy deliveries
PRD	Price Responsive Demand
Unrestricted Peak	Peak load prior to any reduction for load management or voltage reduction.
Zone	Areas within the PJM Control Area, as defined in the PJM Reliability Assurance Agreement

Executive Summary

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

- The report includes a 20 year long-term forecasts of peak loads, net energy, load management, distributed solar generation, plug-in electric vehicles, and battery storage for each PJM zone, region, locational deliverability area (LDA), and the total RTO.
- New to the report this year is a table for the total load associated with adjustments to summer peak loads (Table B-9b available on the PJM Website). All tables are now provided in excel format for ease of use.
- Residential, Commercial, and Industrial sector models were estimated with data from 2014 through 2023. Hourly models were estimated with data from 2015 to August 2024. Weather scenarios were simulated with data from years 1993 through 2023, generating 403 scenarios.
- The economic forecast used was Moody's Analytics' September 2024 release.

Energy Information Administration & Vendor Data

The Energy Information Administration (EIA) did not publish an Annual Energy Outlook (AEO) update in 2024 as they revamp models and make improvements to capture emerging technologies. Therefore, the 2023 update of Itron's end-use data provides the basis for appliance saturation rates, efficiency, and intensity and is consistent with the EIA's 2023 AEO. PJM obtained additional information from certain zones on Residential saturation rates based on their own load research. Details on zones providing information are presented in the supplement.

Consultant forecasts for behind the meter solar/battery and electric vehicles including light, medium & heavy duty were provided by S&P Global.

- The behind the meter solar/battery values were derived by PJM from a forecast obtained from SPGCI
- The electric vehicle values were derived by PJM from a forecast obtained from SPGCI

Compared to the 2024 Load Report, the 2025 PJM RTO summer peak forecast shows the following changes for three years of interest:

Next Year:		
Delivery	RPM Auction	RTEP Study
2025	**2026**	**2030**
+651 MW	**+2,134** MW	**+16,010**MW
(0.4%)	*(1.4%)*	*(9.5%)*

Load Adjustments

The forecasts of the following zones have been adjusted to account for large, unanticipated load changes, market adjustments, and peak shaving adjustments (see **Tables B-9** and **B-9b** and the supplement for details available on the PJM Website):

Zones	Adjusted to account for:
AEP	growth in data center load and a chip processing plant
APS, ATSI, BGE, DAYTON, PECO, and PL	growth in data center load
COMED	growth in data center load and an electric vehicle battery plant
DEOK	adjusted to account for growth in a steel facility
DOM	growth in data center load and a voltage optimization program
PS	growth in data center load and port electrification
EKPC	a peak shaving program that commenced in the 2023 DY
ATSI and DOM	Non-Retail Behind-the-Meter Generation (NRBTMG) transitioning to participation as Demand Response in the Reliability Pricing Model

Summer & Winter Summary

Summer peak load growth for the PJM RTO

- Projected to average 3.1% per year over the next 10-year period and 2.0% over the next 20 years.
- Summer peak is forecasted to be 209,923 MW in 2035, a 10-year increase of 55,779 MW, and reaches 228,544 MW in 2045, a 20-year increase of 74,400 MW.
- Annualized 10-year growth rates for individual zones range from 0.1% to 6.3%; median of 0.7%.

Winter Peak Load Growth – PJM RTO

- Projected to average 3.8% per year over the next 10-year period, and 2.4% over the next 20 years.
- The PJM RTO winter peak load in 2034/35 is forecasted to be 198,175 MW, a 10-year increase of 62,048 MW, and reaches 218,760 MW in 2044/45, a 20-year increase of 82,633 MW.
- Annualized 10-year growth rates for individual zones range from 0.1% to 6.0%; median of 1.6%.

Net Energy Load Growth – PJM RTO

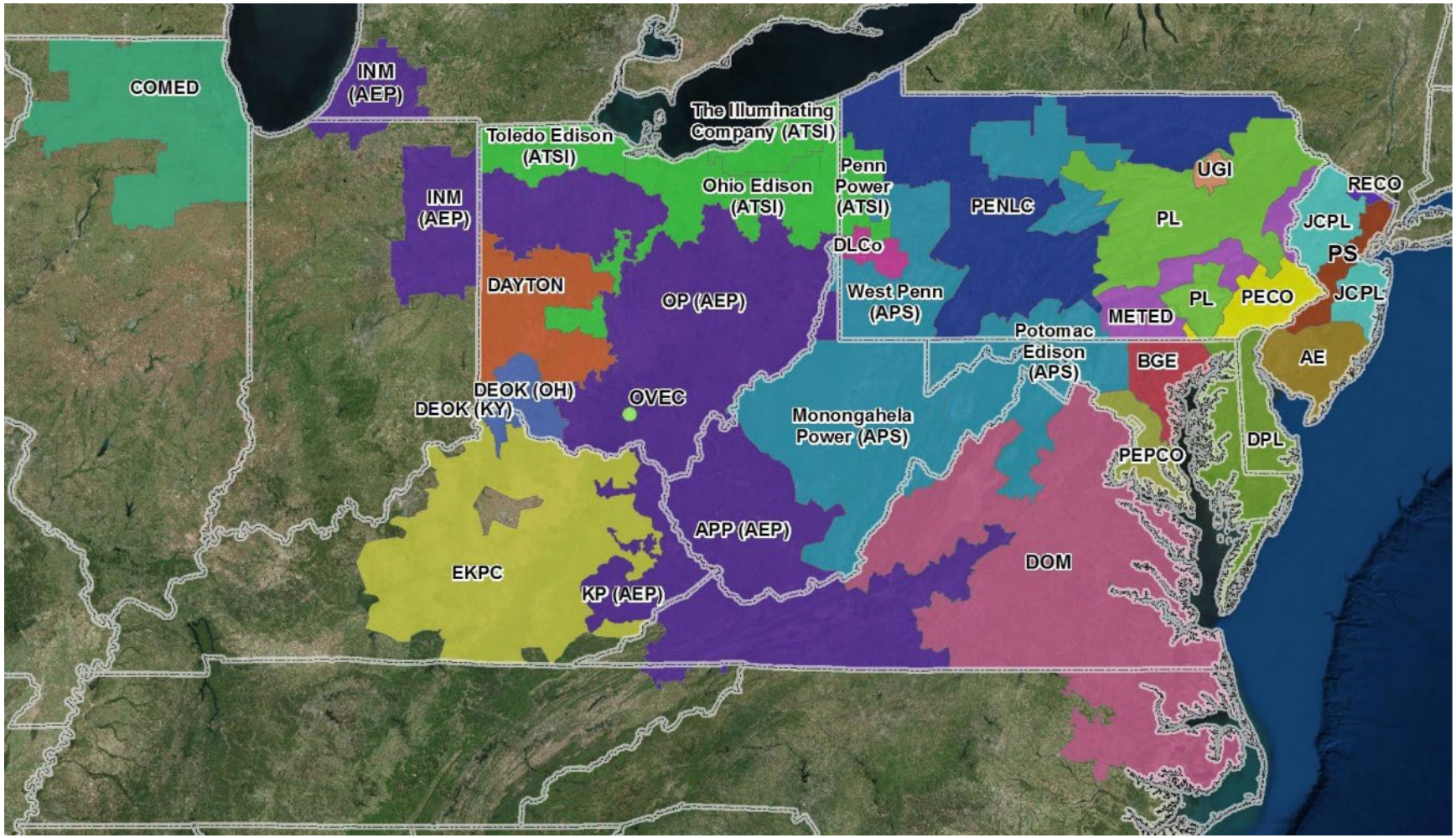
- Projected to average 4.8% per year over the next 10-year period, and 2.9% over the next 20-years.
- Total PJM RTO energy is forecasted to be 1,328,045 GWh in 2035, a 10-year increase of 495,264 GWh, and reaches 1,482,068 GWh in 2045, a 20-year increase of 649,287 GWh.
- Annualized 10- year growth rates for individual zones range from 0.2% to 8.4%; median of 1.6%.

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 battery storage (in summer peak), additions for plug-in electric vehicles, and prior to reductions for load management impacts.

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

PJM Map


COMED
INM (AEP)
Toledo Edison (ATSI)
The Illuminating Company (ATSI)
Ohio Edison (ATSI)
Penn Power (ATSI)
UGI
RECO
PENLC
PL
JCPL
DLCo
PS
DAYTON
OP (AEP)
West Penn (APS)
PL
PECO
JCPL
METED
Potomac Edison (APS)
BGE
AE
DEOK (OH)
DEOK (KY)
OVEC
Monongahela Power (APS)
DPL
PEPCO
APP (AEP)
DOM
EKPC
KP (AEP)

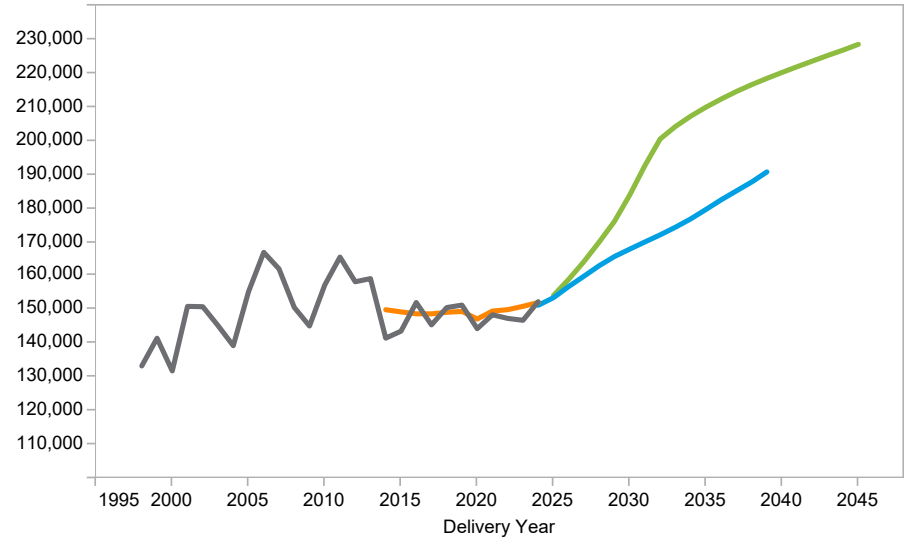
PJM RTO, LDA, and Zonal Dashboards

Click below to jump to an LDA or PJM Zone's data page

PJM RTO	MAAC	E-MAAC	S-MAAC	PJM Western
AE	BGE	DPL	JCPL	METED
PECO	PENLC	PEPCO	PL	PS
RECO	UGI	AEP	APS	ATSI
COMED	DAYTON	DEOK	DLCO	EKPC
DOM				

PJM RTO

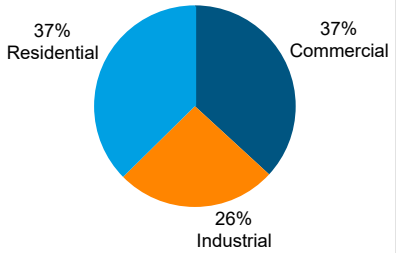
Summer Peak



Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*74.3*
Avg Summer Max Temp	*95.2*
Avg Winter Daily Temp	*34.3*
Avg Winter Min Temp	*4.1*

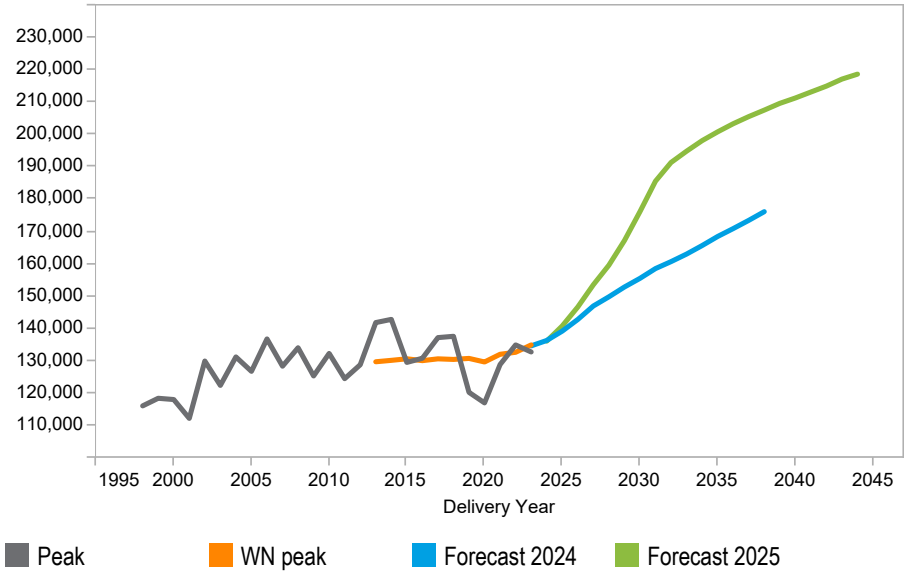
RCI Makeup



Zonal 10/15/20 Year Load Growth

SUMMER	3.1%	2.4%	2.0%
WINTER	3.8%	2.9%	2.4%

Winter Peak



LDAs

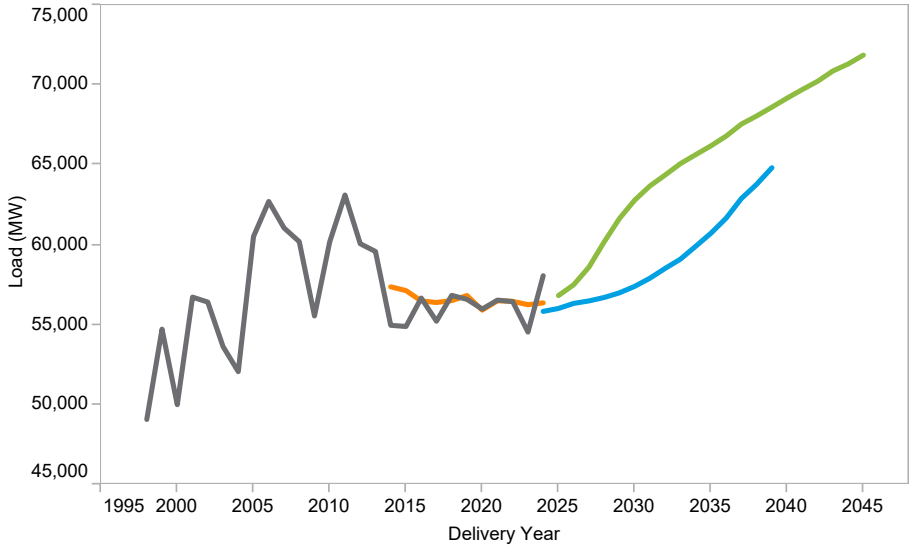
PJM Mid-Atlantic	Central MAAC
Eastern MAAC	Western MAAC
Southern MAAC	PJM West

Zones

AE	DAYTON	JCPL	PEPCO
AEP	DEOK	METED	PL
APS	DLCO	OVEC	PS
ATSI	DOM	PECO	RECO
BGE	DPL	PENLC	UGI
COMED	EKPC		

PJM Mid-Atlantic (MAAC)

Summer Peak



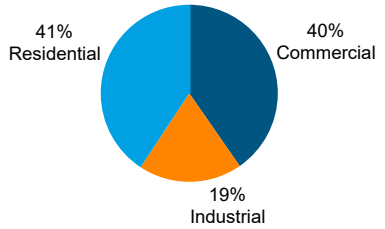
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*74.8*
Avg Summer Max Temp	*96.3*
Avg Winter Daily Temp	*35.1*
Avg Winter Min Temp	*6.6*

Zonal 10/15/20 Year Load Growth

SUMMER	1.5%	1.3%	1.2%
WINTER	2.7%	2.2%	1.9%

RCI Makeup



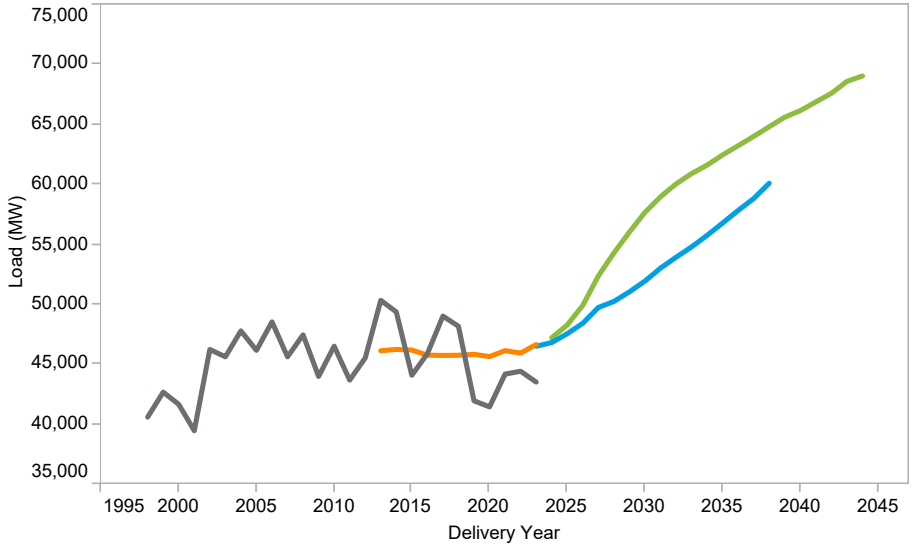
Zones

AE	JCPL	PENLC	PSEG
BGE	METED	PEPCO	RECO
DPL	PECO	PL	UGI

LDAs

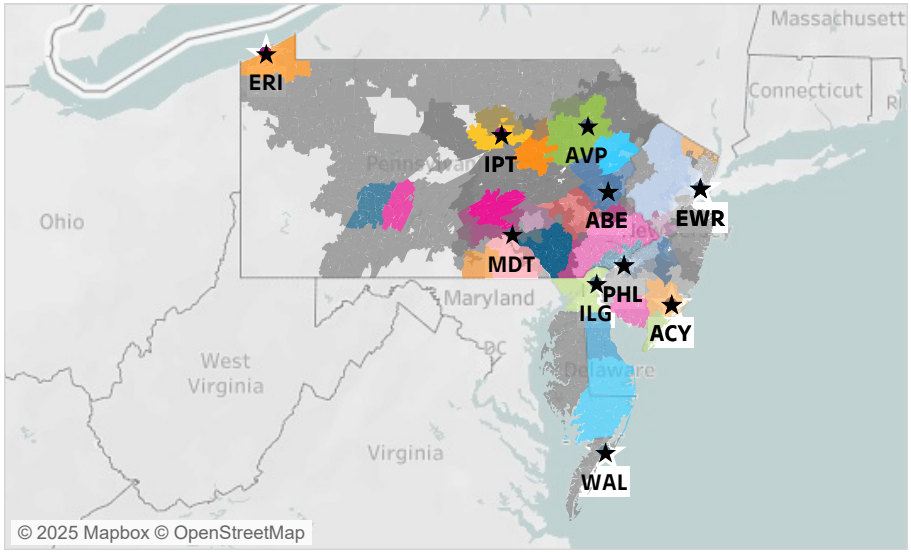
E-MAAC	C-MAAC
S-MAAC	W-MAAC

Winter Peak



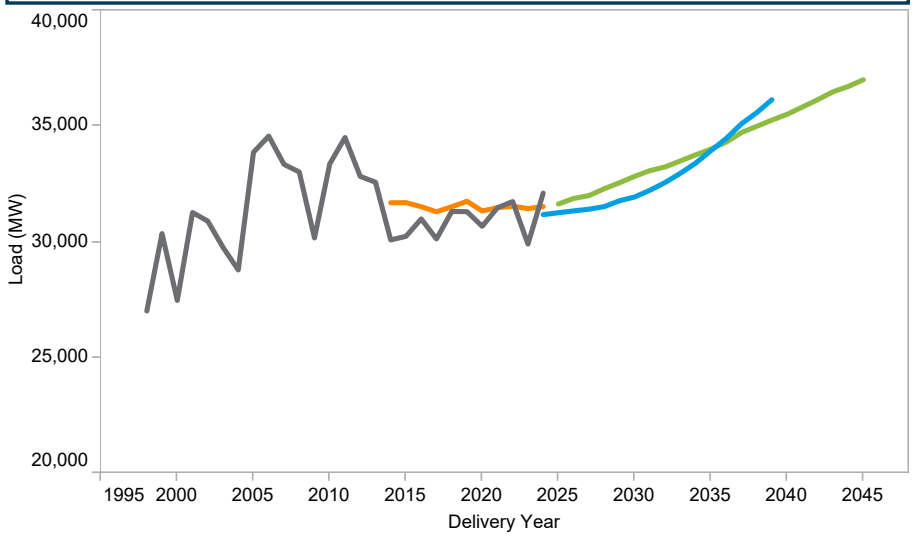
Peak WN peak Forecast 2024 Forecast 2025

Metropolitan Statistical Areas and Weather Stations



PJM Eastern Mid-Atlantic (E-MAAC)

Summer Peak



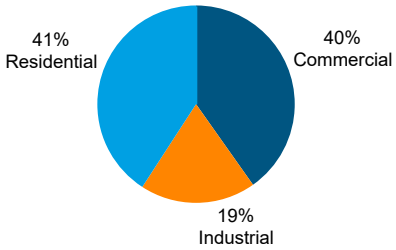
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*75.7*
Avg Summer Max Temp	*97.5*
Avg Winter Daily Temp	*36.4*
Avg Winter Min Temp	*7.9*

Zonal 10/15/20 Year Load Growth

SUMMER	0.7%	0.8%	0.8%
WINTER	2.7%	2.3%	2.1%

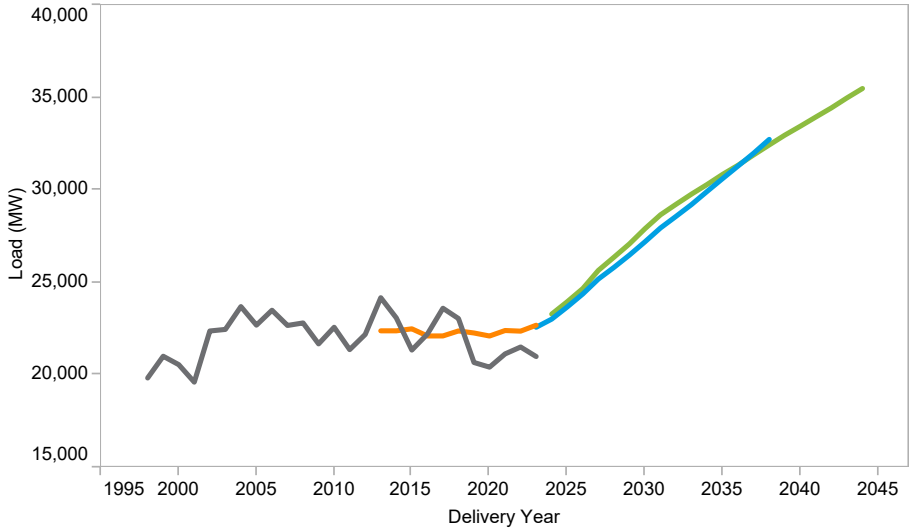
RCI Makeup



Zones

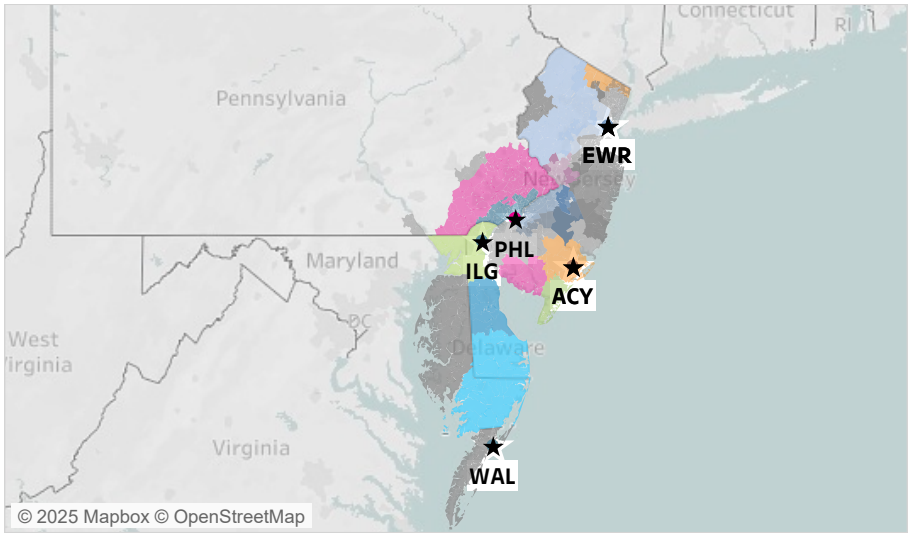
AE DPL JCPL PECO PS RECO

Winter Peak



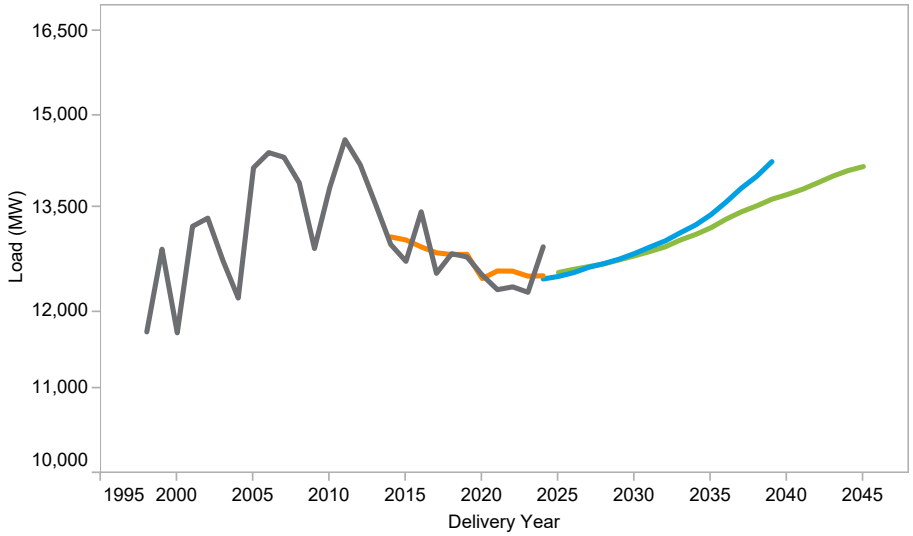
Peak WN peak Forecast 2024 Forecast 2025

Metropolitan Statistical Areas and Weather Stations



PJM Southern Mid-Atlantic (S-MAAC)

Summer Peak



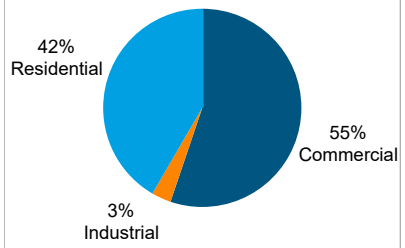
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*77.1*
Avg Summer Max Temp	*98.0*
Avg Winter Daily Temp	*38.1*
Avg Winter Min Temp	*10.4*

Zonal 10/15/20 Year Load Growth

SUMMER	0.5%	0.6%	0.6%
WINTER	0.8%	0.8%	0.7%

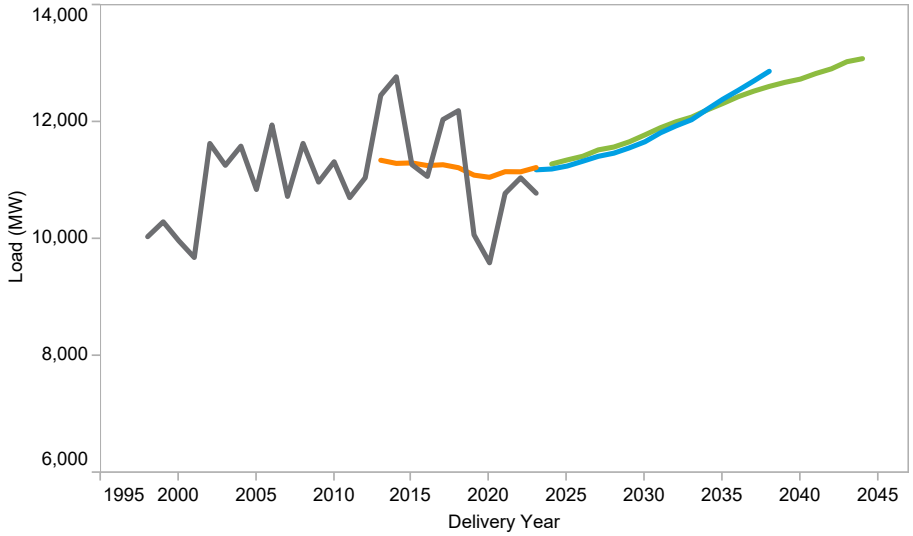
RCI Makeup



Zones

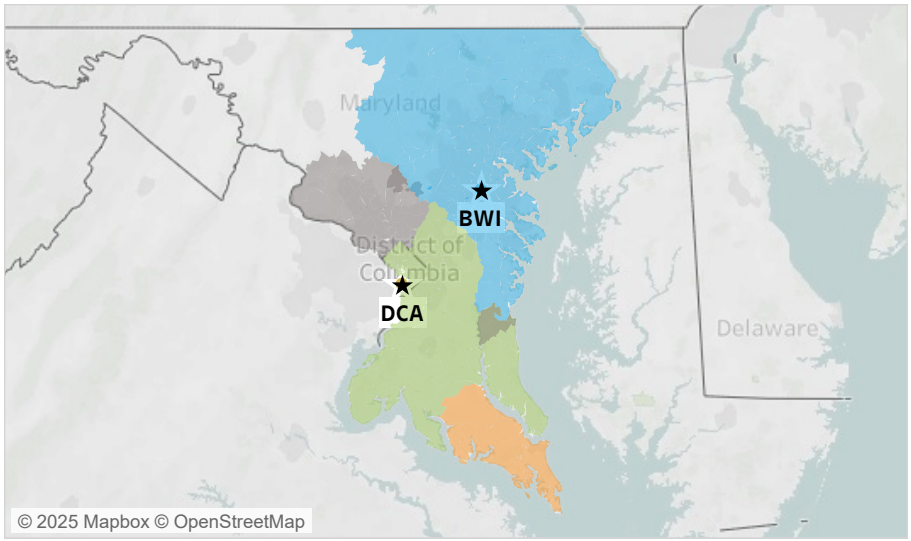
BGE PEPCO

Winter Peak



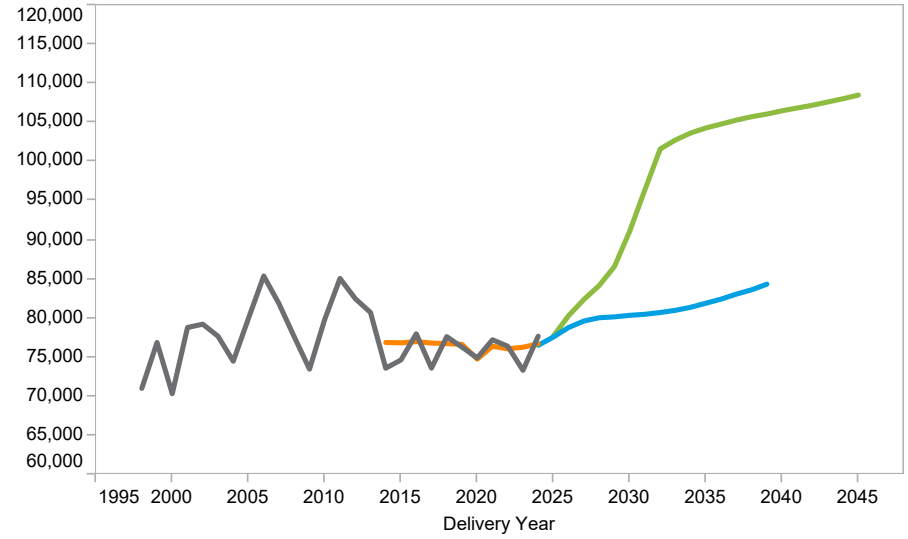
Peak WN peak Forecast 2024 Forecast 2025

Metropolitan Statistical Areas and Weather Stations



PJM Western

Summer Peak



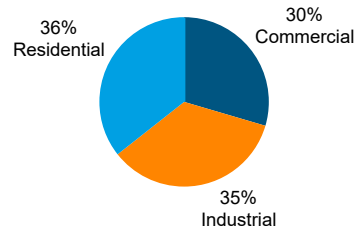
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*73.2*
Avg Summer Max Temp	*93.2*
Avg Winter Daily Temp	*32.2*
Avg Winter Min Temp	*-0.7*

Zonal 10/15/20 Year Load Growth

SUMMER	3.0%	2.1%	1.7%
WINTER	3.7%	2.6%	2.1%

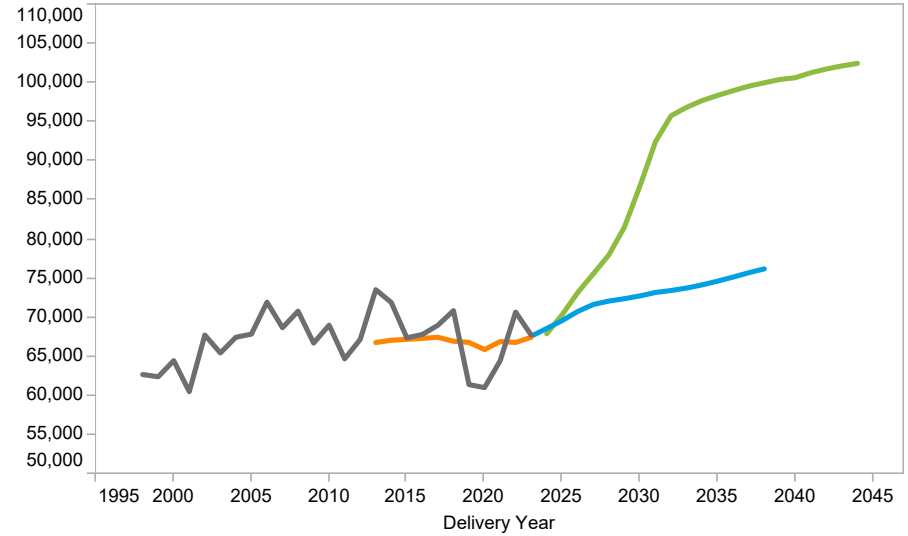
RCI Makeup



Zones

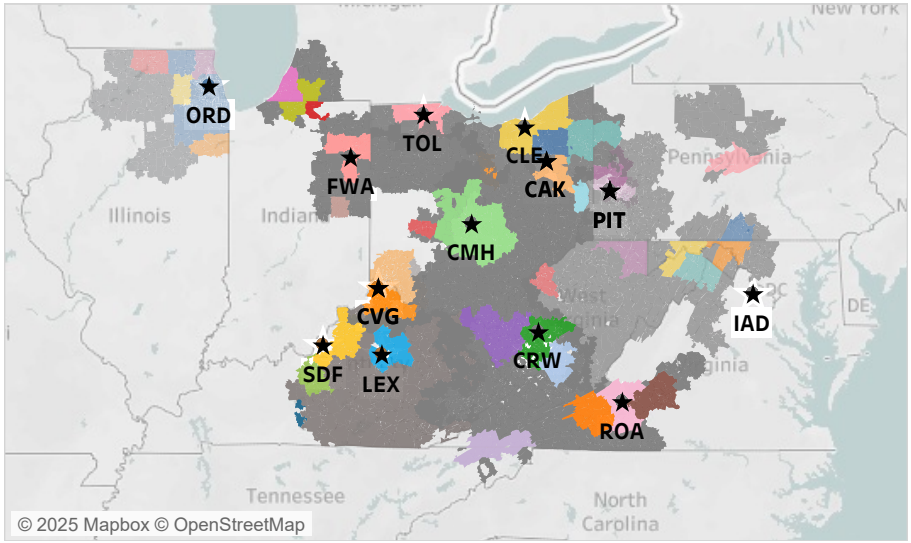
AEP	COMED	DLCO
APS	DAYTON	EKPC
ATSI	DEOK	OVEC

Winter Peak



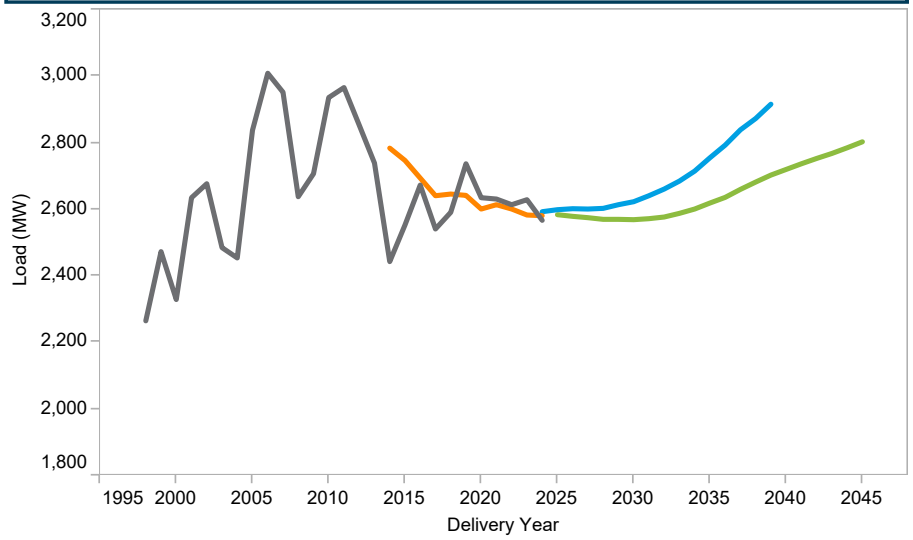
Peak WN peak Forecast 2024 Forecast 2025

Metropolitan Statistical Areas and Weather Stations



Atlantic Electric (AE)

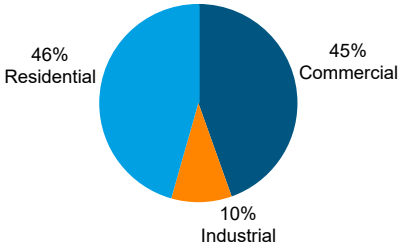
Summer Peak



Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*74.3*
Avg Summer Max Temp	*97.0*
Avg Winter Daily Temp	*36.8*
Avg Winter Min Temp	*6.1*

RCI Makeup



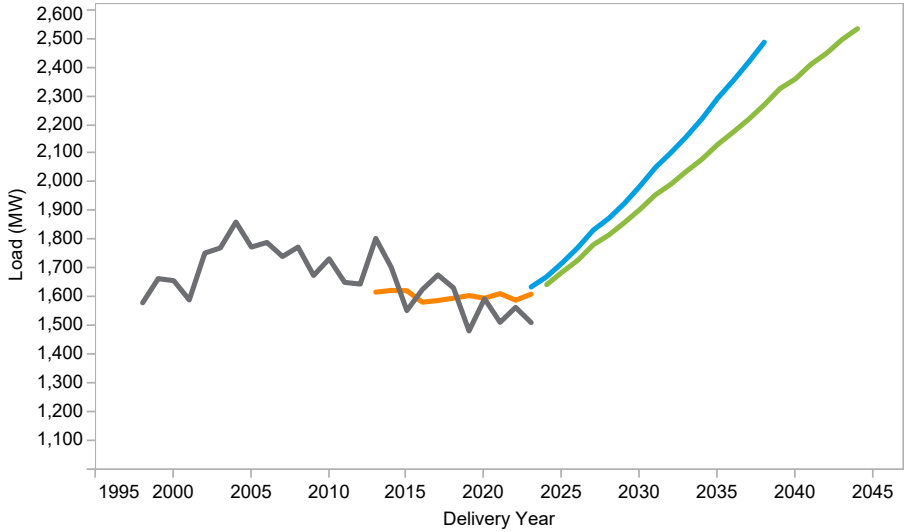
Zonal 10/15/20 Year Load Growth

SUMMER	0.1%	0.3%	0.4%
WINTER	2.4%	2.3%	2.2%

LDAs

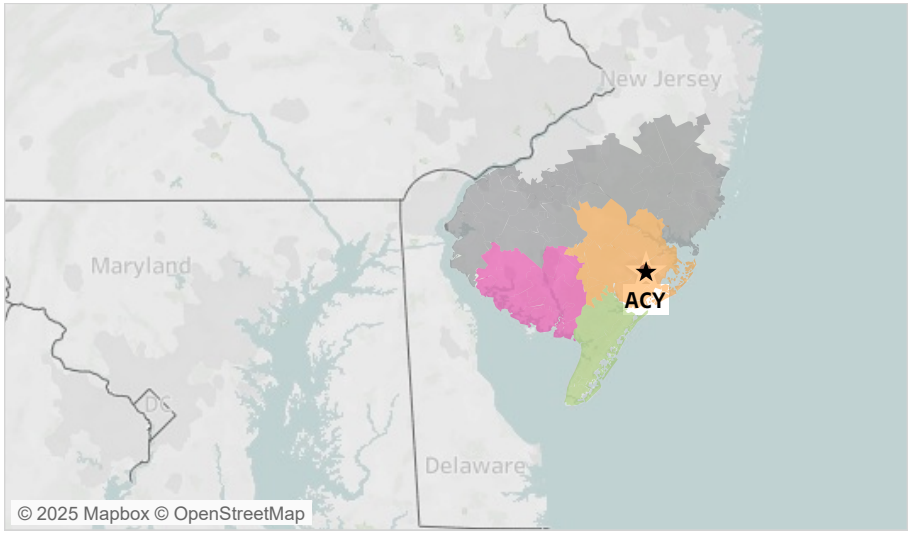
EASTERN MID-ATLANTIC PJM MID-ATLANTIC PJM RTO

Winter Peak



Peak WN peak Forecast 2024 Forecast 2025

Metropolitan Statistical Areas and Weather Stations

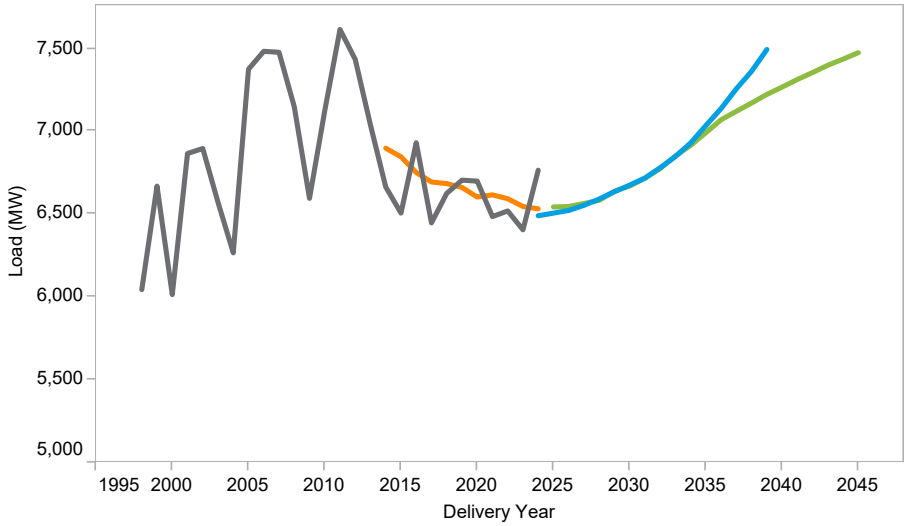


MSA

- AE - Non-Metro
- Atlantic City-Hammonton, NJ
- Ocean City, NJ
- Vineland-Bridgeton, NJ

Baltimore Gas & Electric (BGE)

Summer Peak



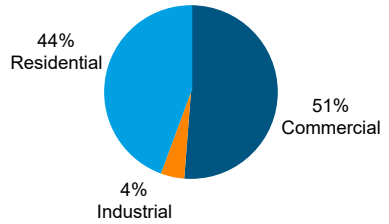
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*76.1*
Avg Summer Max Temp	*98.0*
Avg Winter Daily Temp	*36.9*
Avg Winter Min Temp	*8.0*

Zonal 10/15/20 Year Load Growth

SUMMER	0.7%	0.7%	0.7%
WINTER	1.0%	1.0%	0.9%

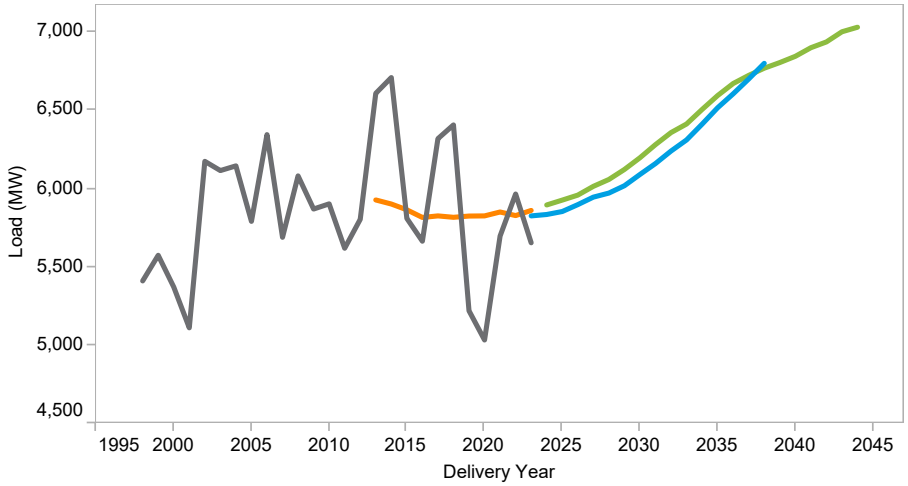
RCI Makeup



LDAs

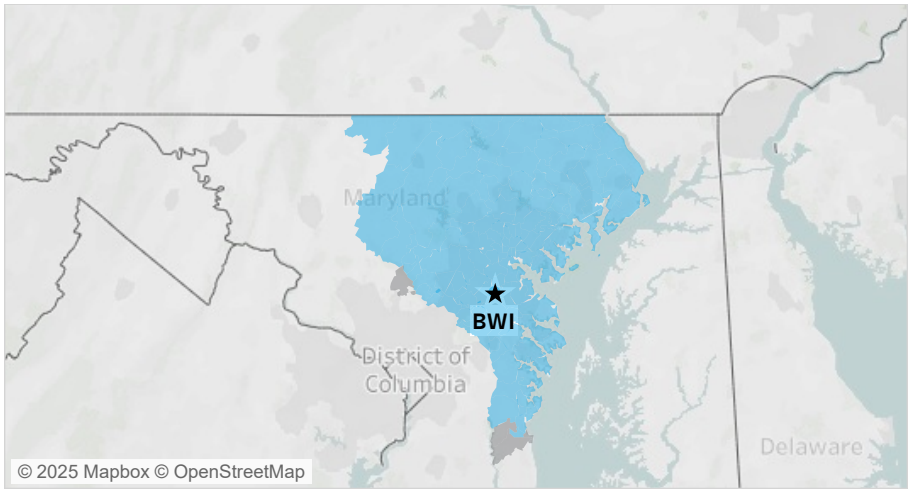
CENTRAL MID-ATLANTIC PJM MID-ATLANTIC PJM RTO
SOUTHERN MID-ATLANTIC

Winter Peak



Peak WN peak Forecast 2024 Forecast 2025

Metropolitan Statistical Areas and Weather Stations



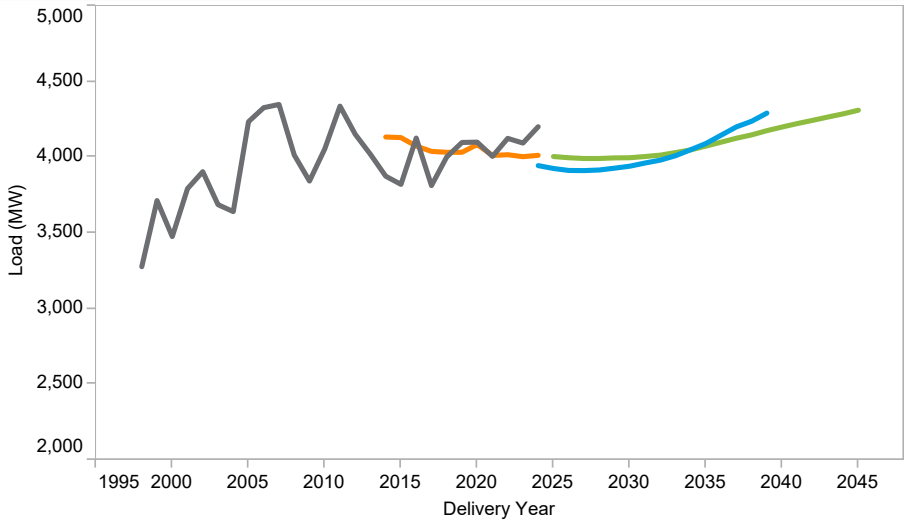
MSA

Baltimore-Columbia-Towson, MD

BGE - Non-Metro

Delmarva Power and Light (DPL)

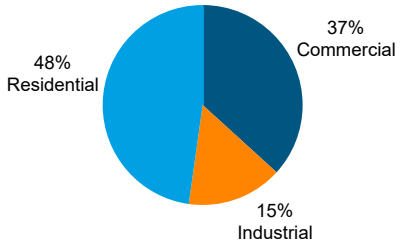
Summer Peak



Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*75.5*
Avg Summer Max Temp	*95.1*
Avg Winter Daily Temp	*37.2*
Avg Winter Min Temp	*9.7*

RCI Makeup



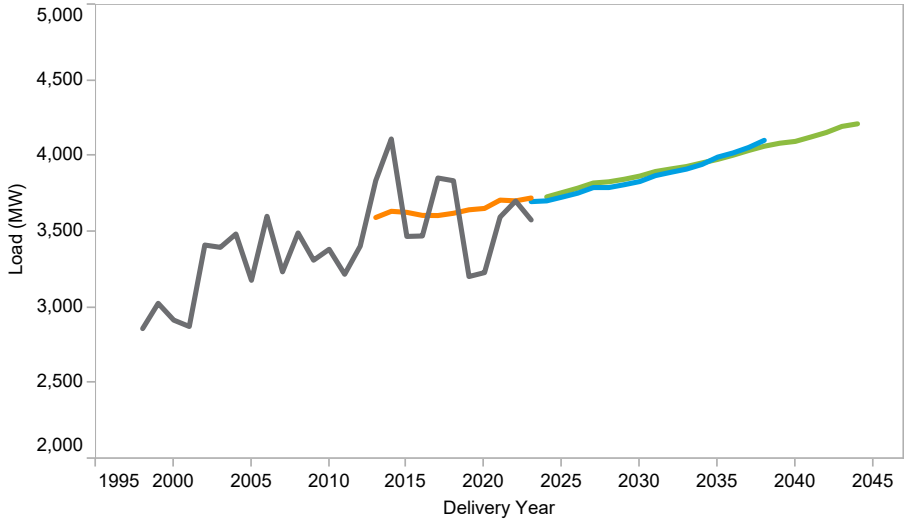
Zonal 10/15/20 Year Load Growth

SUMMER	0.2%	0.3%	0.4%
WINTER	0.6%	0.6%	0.6%

LDAs

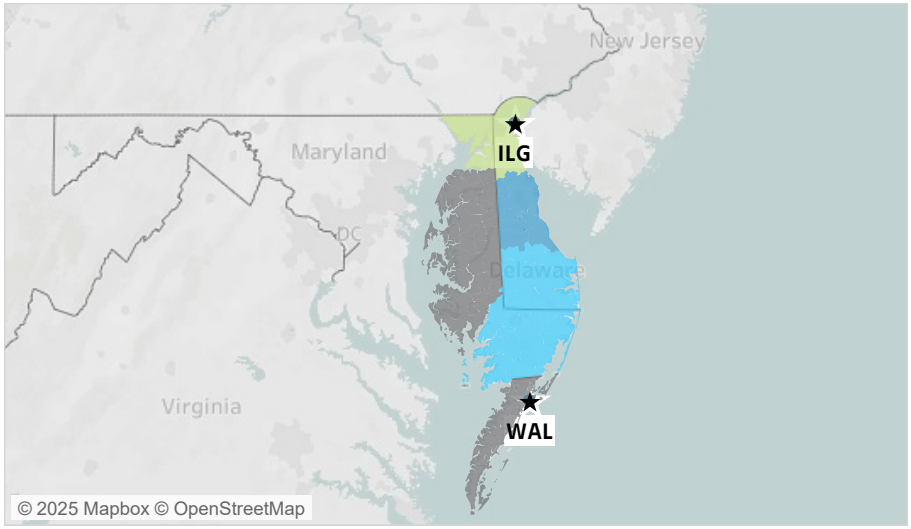
EASTERN MID-ATLANTIC PJM MID-ATLANTIC PJM RTO

Winter Peak



Peak WN peak Forecast 2024 Forecast 2025

Metropolitan Statistical Areas and Weather Stations

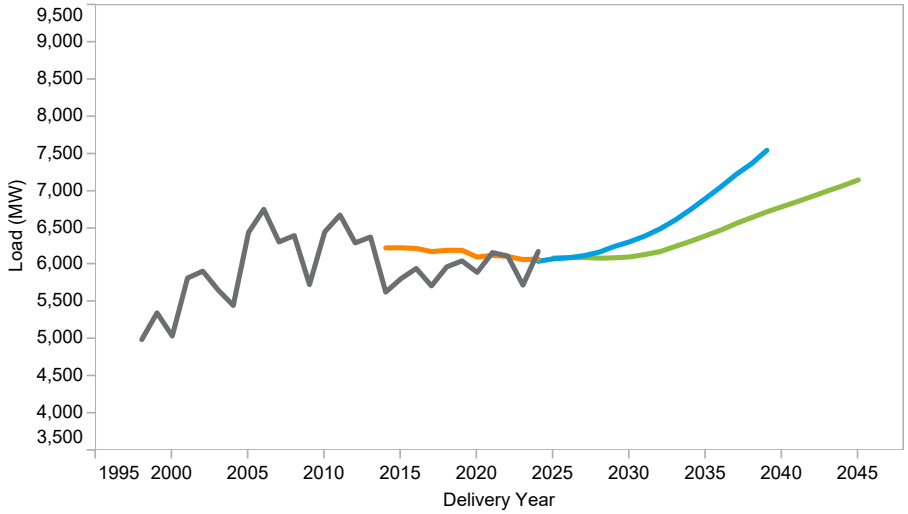


MSA

- Dover, DE
- DPL - Non-Metro
- Salisbury, MD-DE
- Wilmington, DE-MD-NJ

Jersey Central Power and Light (JCPL)

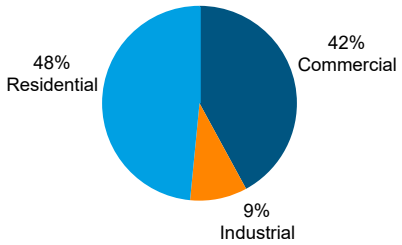
Summer Peak



Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*75.7*
Avg Summer Max Temp	*98.1*
Avg Winter Daily Temp	*36.1*
Avg Winter Min Temp	*7.5*

RCI Makeup



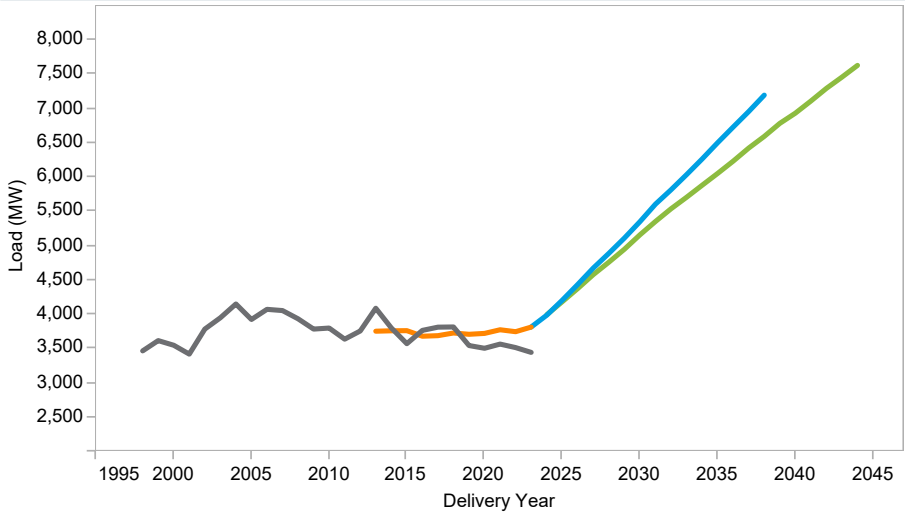
Zonal 10/15/20 Year Load Growth

SUMMER	0.5%	0.7%	0.8%
WINTER	3.9%	3.6%	3.3%

LDAs

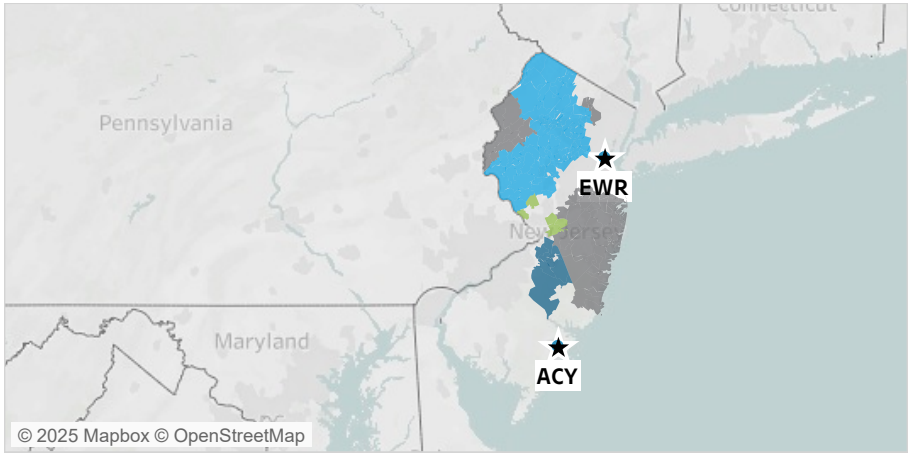
EASTERN MID-ATLANTIC GPU PJM MID-ATLANTIC PJM RTO

Winter Peak



Peak WN peak Forecast 2024 Forecast 2025

Metropolitan Statistical Areas and Weather Stations

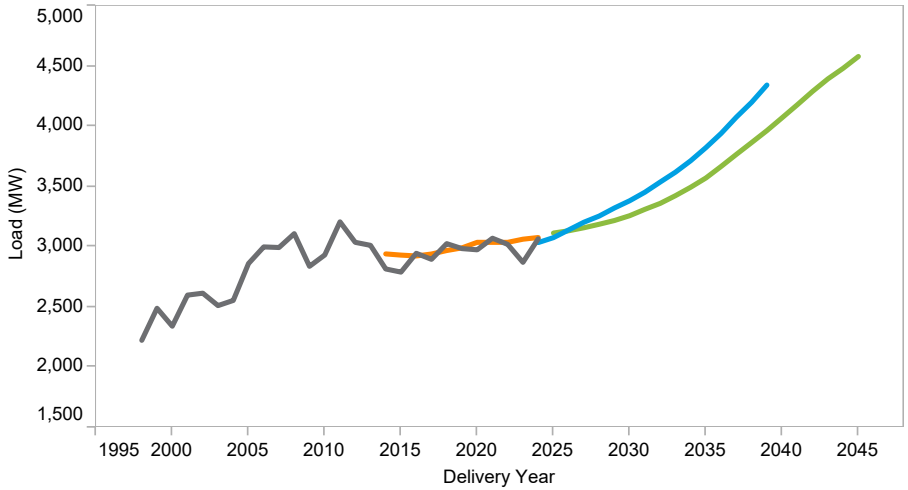


MSA

- Camden, NJ
- JCPL - Non-Metro
- Newark, NJ-PA
- Trenton, NJ

Metropolitan Edison (METED)

Summer Peak



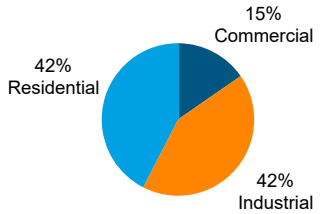
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*74.7*
Avg Summer Max Temp	*95.8*
Avg Winter Daily Temp	*34.6*
Avg Winter Min Temp	*6.7*

Zonal 10/15/20 Year Load Growth

SUMMER	1.4%	1.8%	1.9%
WINTER	1.6%	2.0%	2.1%

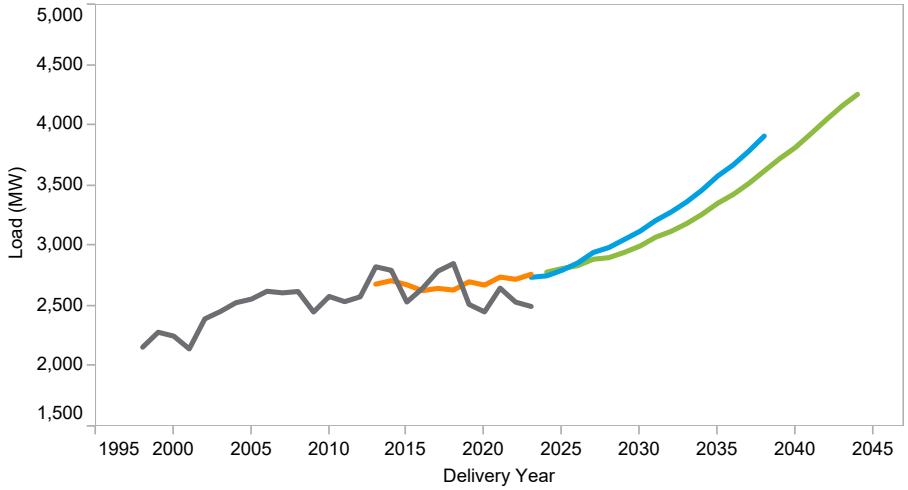
RCI Makeup



LDAs

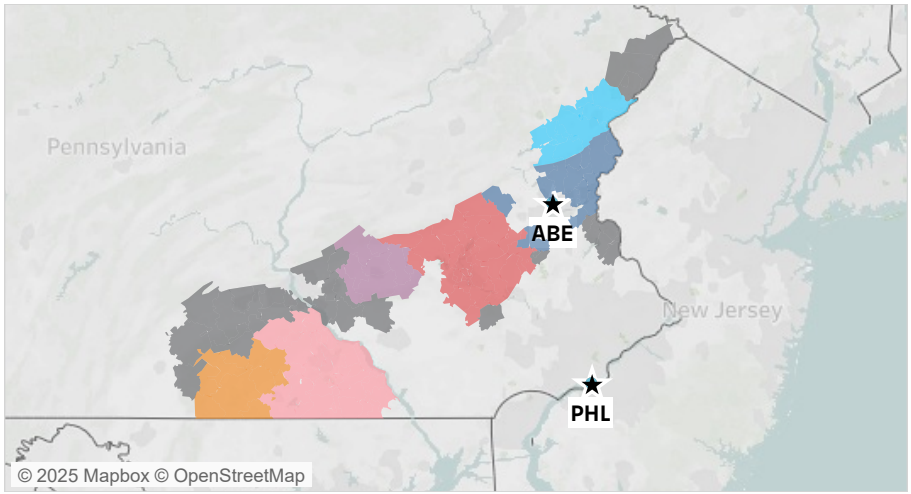
CENTRAL MID-ATLANTIC GPU PJM MID-ATLANTIC PJM RTO WESTERN MID-ATLANTIC

Winter Peak



Peak WN peak Forecast 2024 Forecast 2025

Metropolitan Statistical Areas and Weather Stations

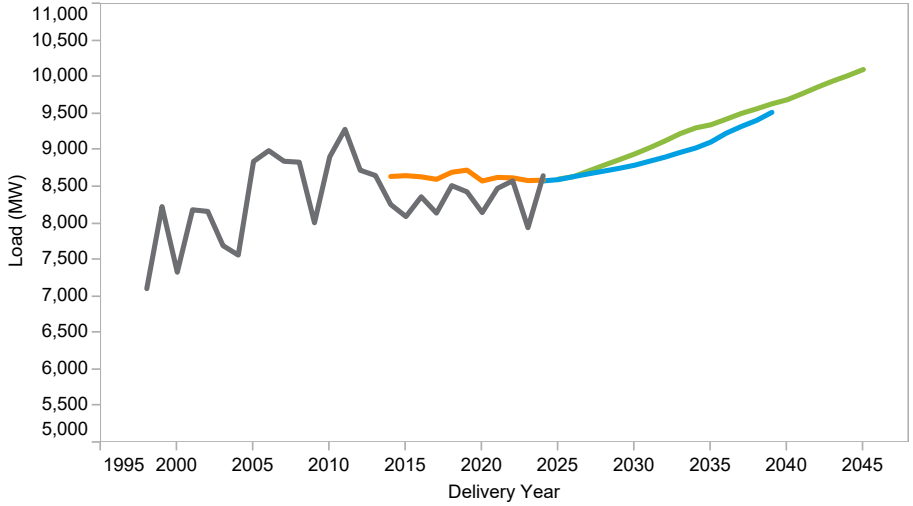


MSA

- Allentown-Bethlehem-Easton, PA-NJ
- East Stroudsburg, PA
- Gettysburg, PA
- Lebanon, PA
- METED - Non-Metro
- Reading, PA
- York-Hanover, PA

PECO Energy (PECO)

Summer Peak



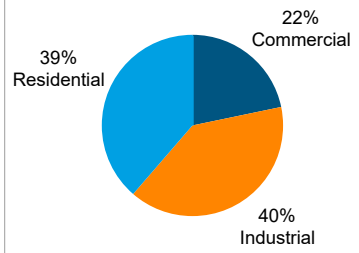
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*76.6*
Avg Summer Max Temp	*97.1*
Avg Winter Daily Temp	*36.8*
Avg Winter Min Temp	*9.4*

Zonal 10/15/20 Year Load Growth

SUMMER	0.8%	0.8%	0.8%
WINTER	1.3%	1.1%	1.0%

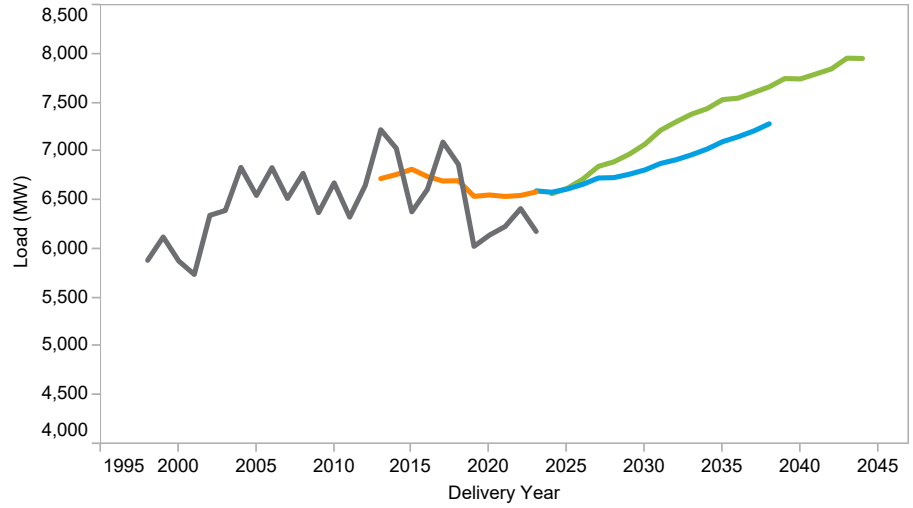
RCI Makeup



LDAs

EASTERN MID-ATLANTIC PJM MID-ATLANTIC PJM RTO

Winter Peak



Peak WN peak Forecast 2024 Forecast 2025

Metropolitan Statistical Areas and Weather Stations

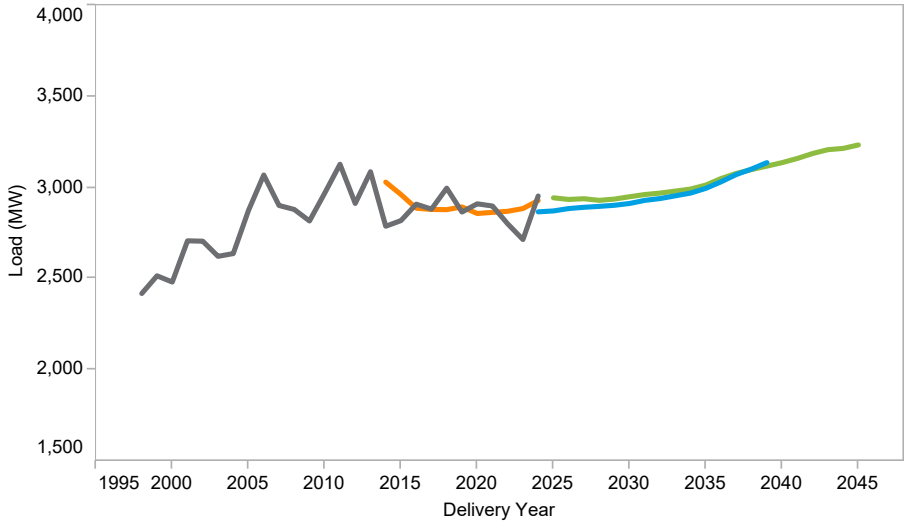


MSA

- Montgomery County-Bucks County-Chester County, PA
- PECO - Non-Metro
- Philadelphia, PA

Pennsylvania Electric Company (PENLC)

Summer Peak



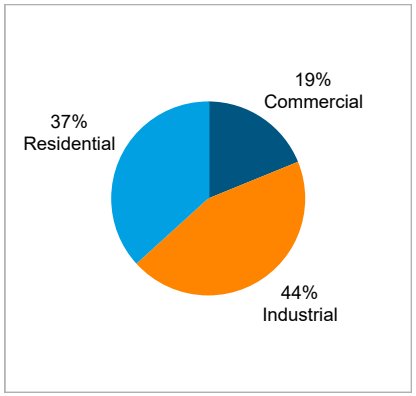
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*71.1*
Avg Summer Max Temp	*91.7*
Avg Winter Daily Temp	*30.5*
Avg Winter Min Temp	*2.1*

Zonal 10/15/20 Year Load Growth

SUMMER	0.2%	0.4%	0.5%
WINTER	0.3%	0.4%	0.4%

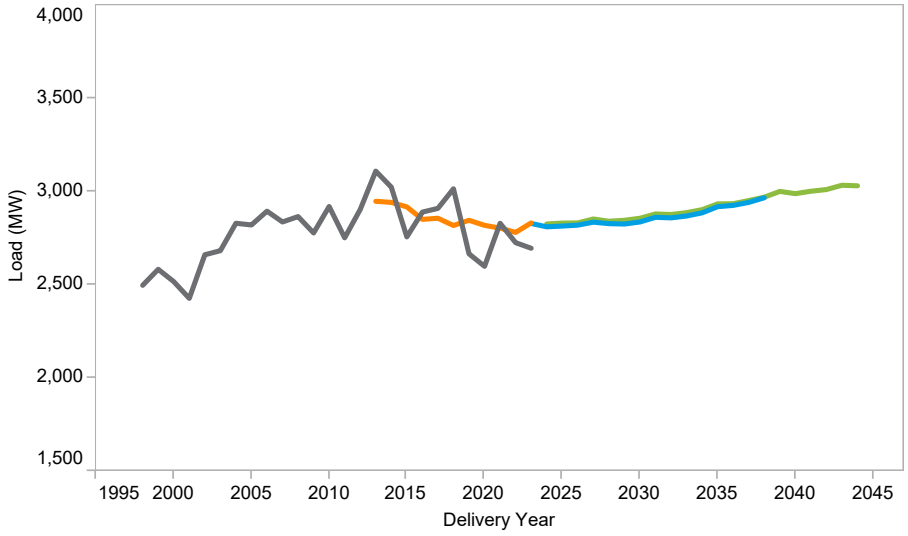
RCI Makeup



LDAs

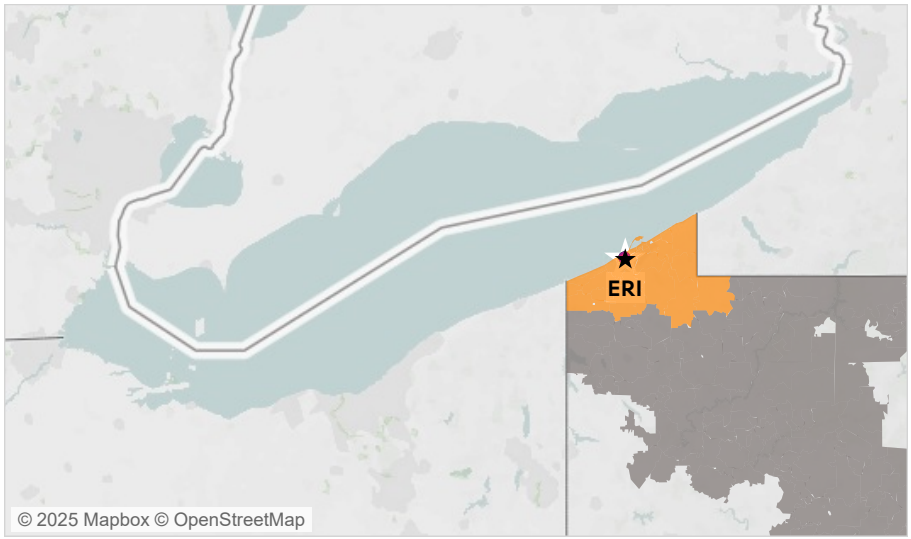
GPU PJM MID-ATLANTIC PJM RTO WESTERN MID-ATLANTIC

Winter Peak



Peak WN peak Forecast 2024 Forecast 2025

Metropolitan Statistical Areas and Weather Stations

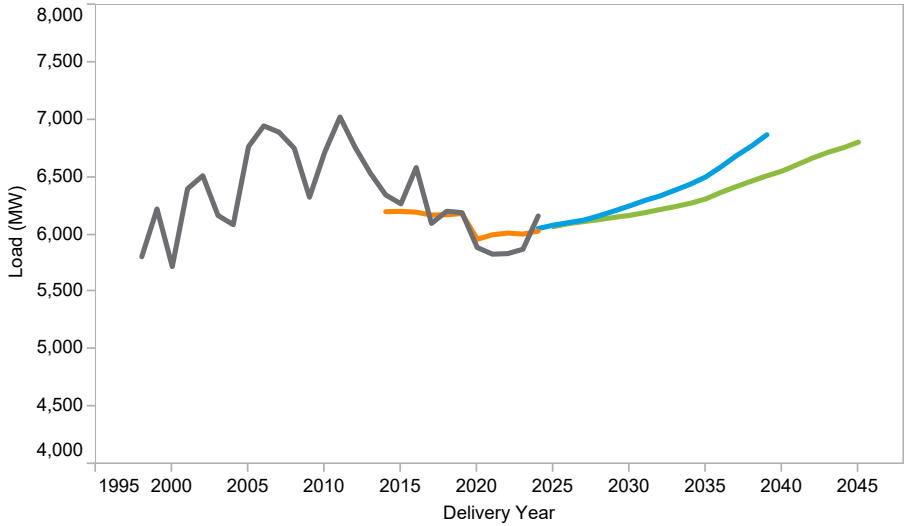


MSA

- Altoona, PA
- Erie, PA
- Johnstown, PA
- PENLC - Non-Metro

Potomac Electric Power (PEPCO)

Summer Peak



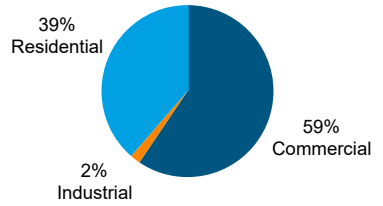
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*78.1*
Avg Summer Max Temp	*98.0*
Avg Winter Daily Temp	*39.2*
Avg Winter Min Temp	*12.8*

Zonal 10/15/20 Year Load Growth

SUMMER	0.4%	0.5%	0.6%
WINTER	0.6%	0.6%	0.6%

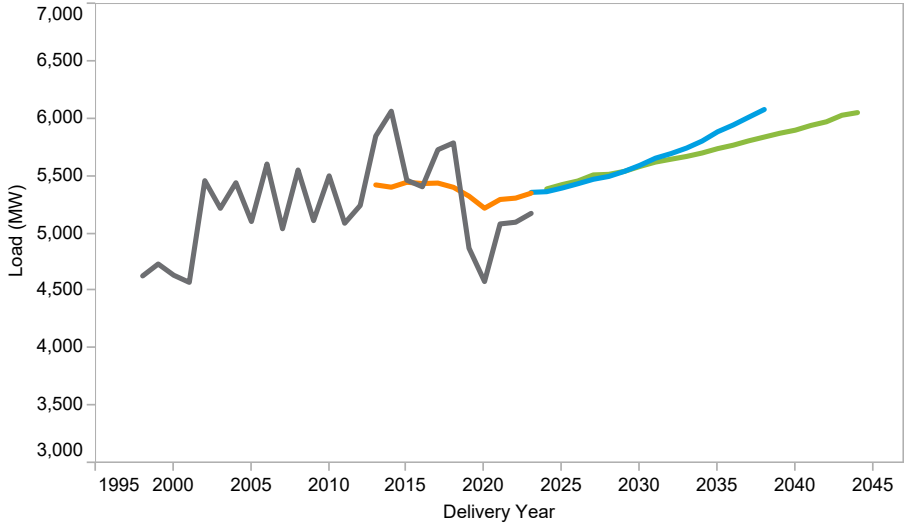
RCI Makeup



LDAs

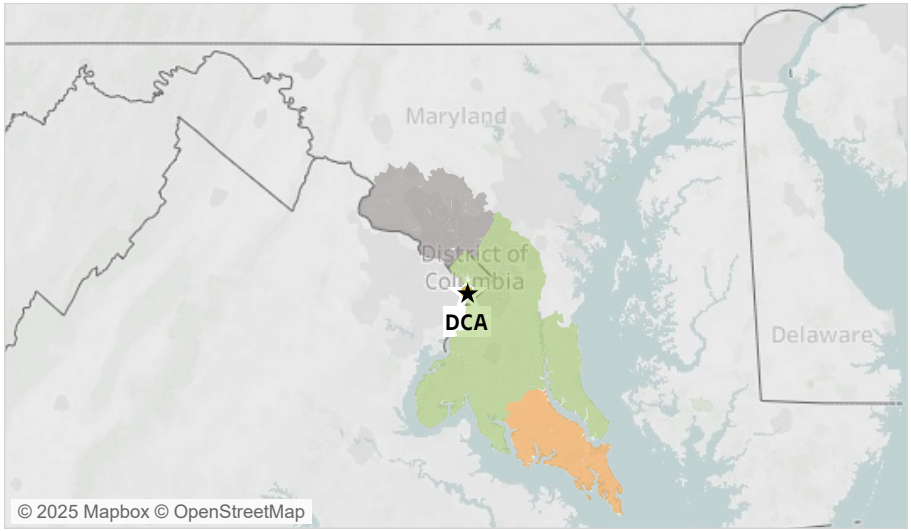
CENTRAL MID-ATLANTIC PJM MID-ATLANTIC PJM RTO
SOUTHERN MID-ATLANTIC

Winter Peak



Peak WN peak Forecast 2024 Forecast 2025

Metropolitan Statistical Areas and Weather Stations

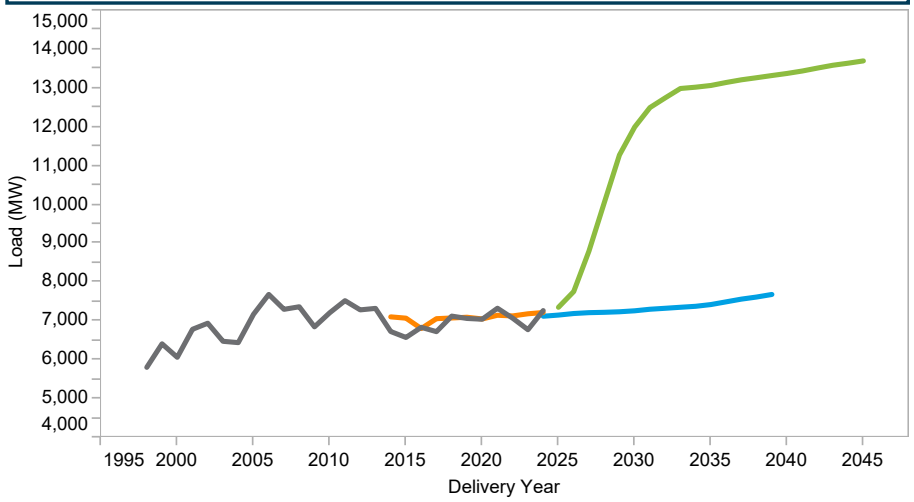


MSA

California-Lexington Park, MD
Washington-Arlington-Alexandria, DC-VA-..
PEPCO - Non-Metro

PPL Electric Utilities (PL)

Summer Peak



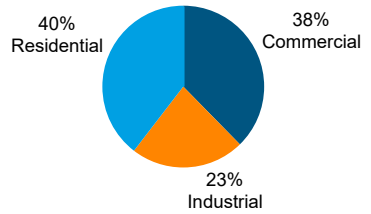
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*72.4*
Avg Summer Max Temp	*94.2*
Avg Winter Daily Temp	*31.7*
Avg Winter Min Temp	*2.9*

Zonal 10/15/20 Year Load Growth

SUMMER	5.9%	4.1%	3.2%
WINTER	5.8%	4.0%	3.0%

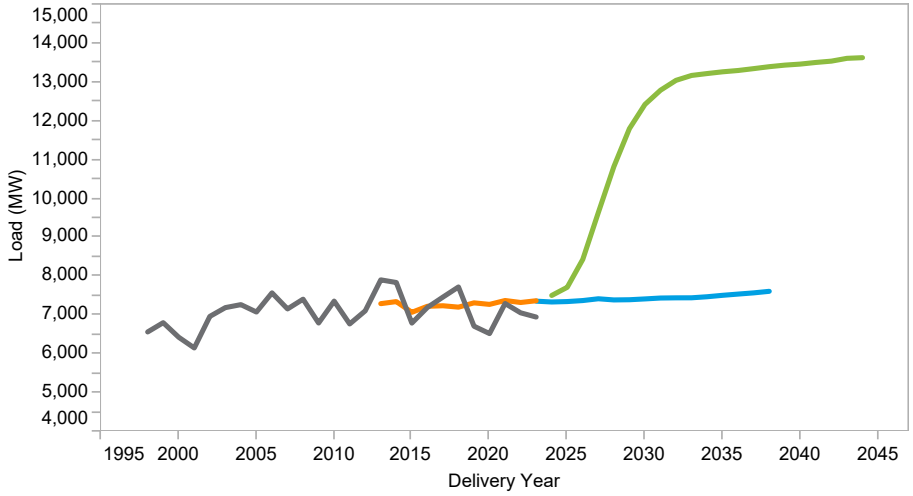
RCI Makeup



LDAs

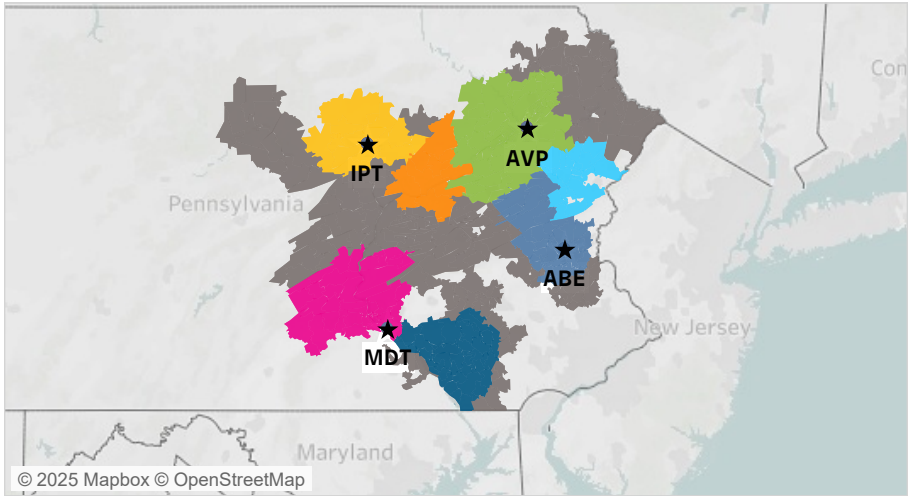
CENTRAL MID-ATLANTIC PJM MID-ATLANTIC PJM RTO
PLGRP WESTERN MID-ATLANTIC

Winter Peak



Peak WN peak Forecast 2024 Forecast 2025

Metropolitan Statistical Areas and Weather Stations

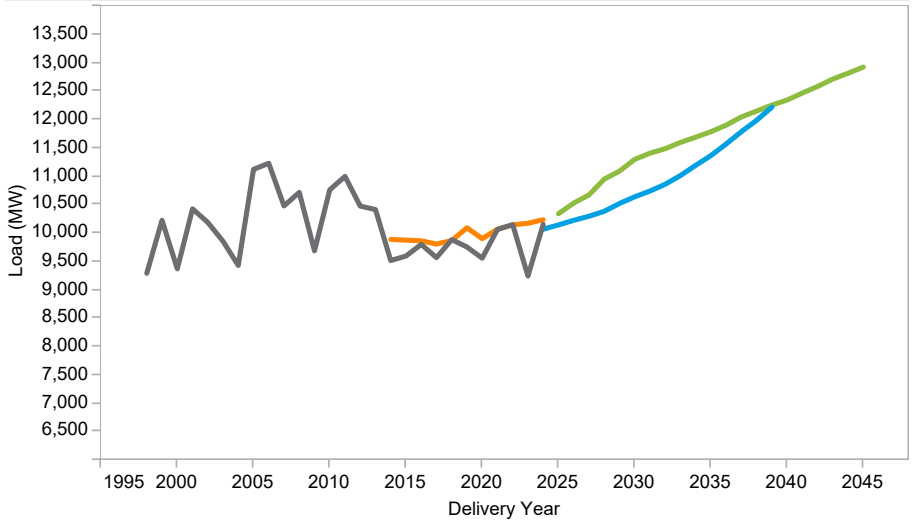


MSA

- Allentown-Bethlehem-Easton, PA-NJ
- Bloomsburg-Berwick, PA
- East Stroudsburg, PA
- Harrisburg-Carlisle, PA
- Lancaster, PA
- PL - Non-Metro
- Scranton--Wilkes-Barre--Hazleton, PA
- Williamsport, PA

Public Service Electric & Gas (PS)

Summer Peak



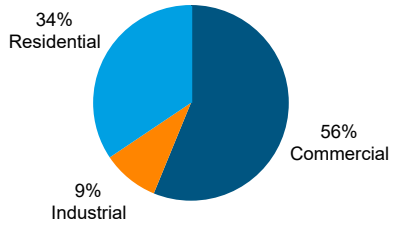
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*76.1*
Avg Summer Max Temp	*98.9*
Avg Winter Daily Temp	*35.8*
Avg Winter Min Temp	*7.4*

Zonal 10/15/20 Year Load Growth

SUMMER	1.3%	1.2%	1.1%
WINTER	4.0%	3.3%	2.9%

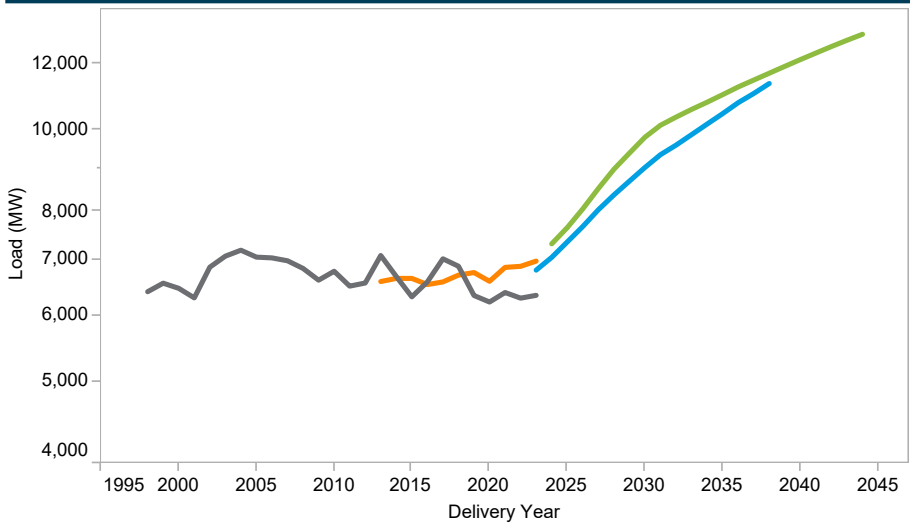
RCI Makeup



LDAs

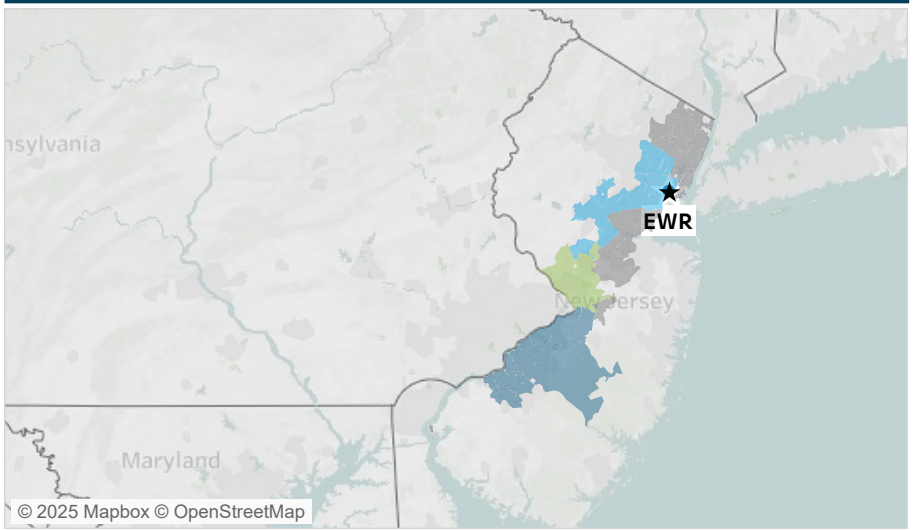
EASTERN MID-ATLANTIC PJM MID-ATLANTIC PJM RTO

Winter Peak



Peak WN peak Forecast 2024 Forecast 2025

Metropolitan Statistical Areas and Weather Stations

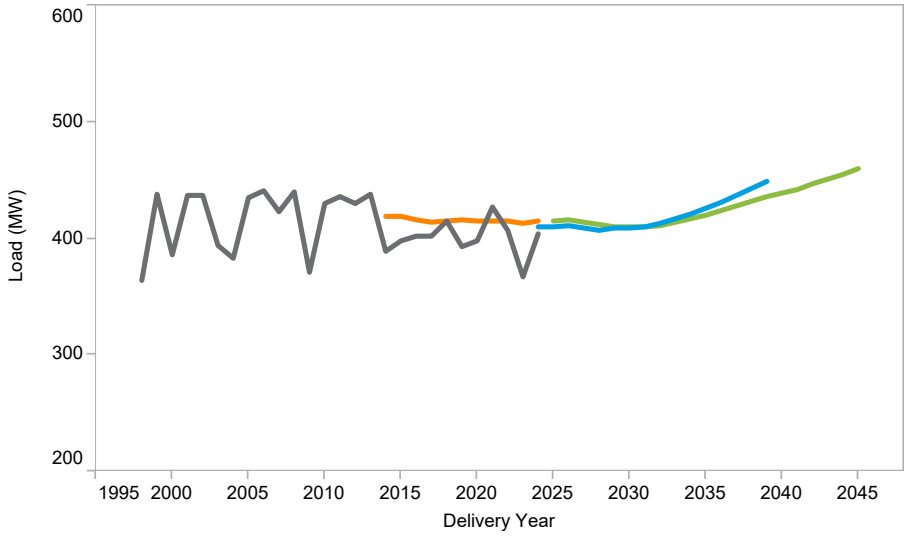


MSA

- Camden, NJ
- Newark, NJ-PA
- PS - Non-Metro
- Trenton, NJ

Rockland Electric Company (RECO)

Summer Peak



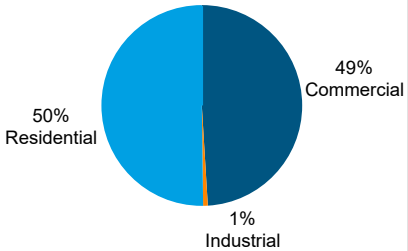
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*76.1*
Avg Summer Max Temp	*98.9*
Avg Winter Daily Temp	*35.8*
Avg Winter Min Temp	*7.4*

Zonal 10/15/20 Year Load Growth

SUMMER	0.1%	0.4%	0.5%
WINTER	2.6%	2.5%	2.3%

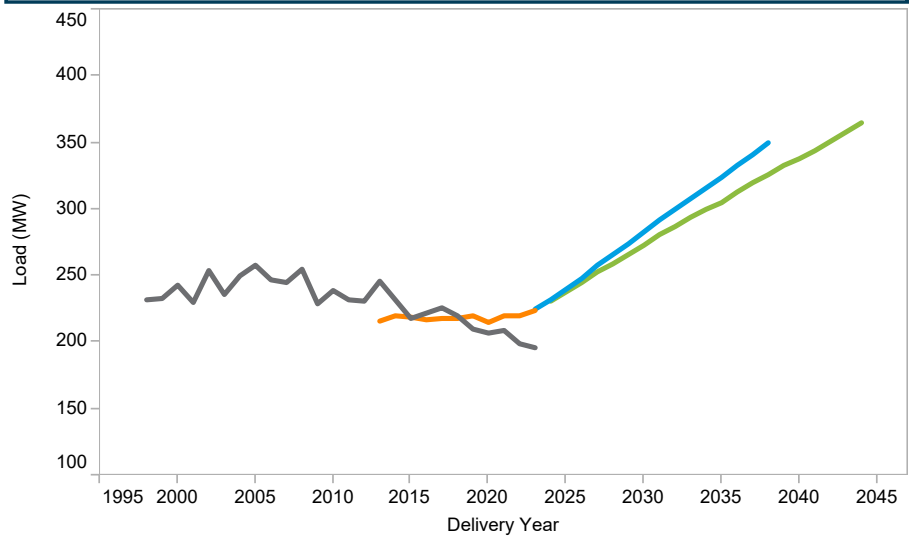
RCI Makeup



LDAs

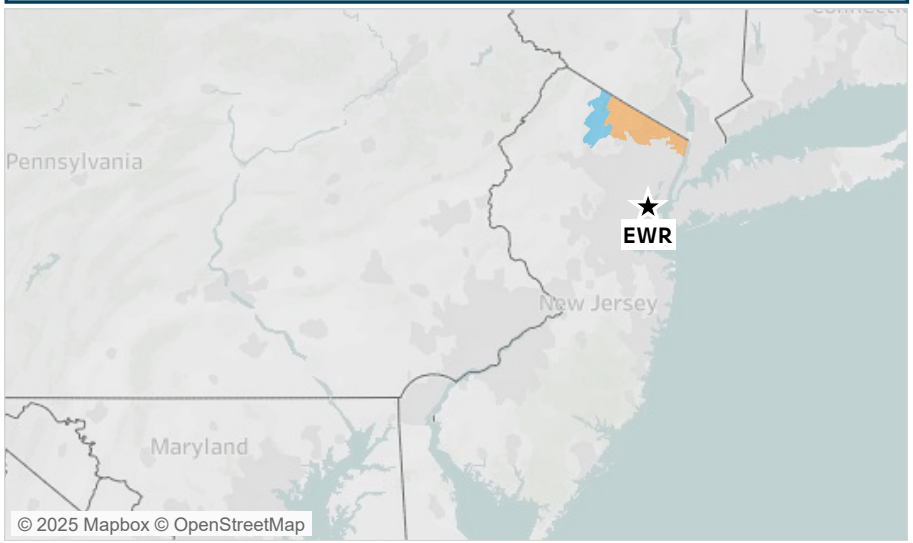
EASTERN MID-ATLANTIC PJM MID-ATLANTIC PJM RTO

Winter Peak



Peak WN peak Forecast 2024 Forecast 2025

Metropolitan Statistical Areas and Weather Stations



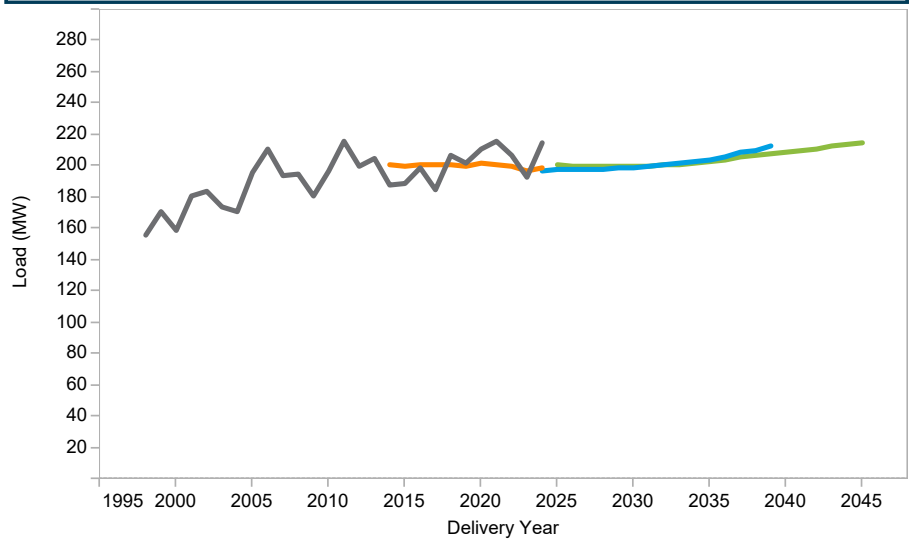
MSA

New York-Jersey City-White Plains, NY-NJ

Newark, NJ-PA

UGI Energy Services (UGI)

Summer Peak



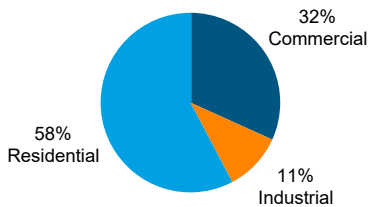
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*70.6*
Avg Summer Max Temp	*93.2*
Avg Winter Daily Temp	*30.1*
Avg Winter Min Temp	*-1.0*

Zonal 10/15/20 Year Load Growth

SUMMER	0.1%	0.3%	0.3%
WINTER	0.1%	0.3%	0.3%

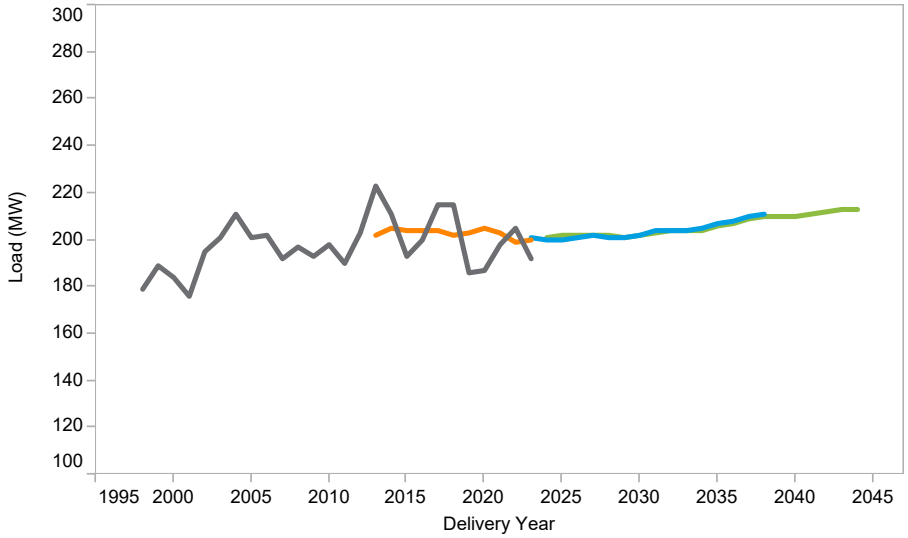
RCI Makeup



LDAs

CENTRAL MID-ATLANTIC PJM MID-ATLANTIC PJM RTO
PLGRP WESTERN MID-ATLANTIC

Winter Peak



Metropolitan Statistical Areas and Weather Stations



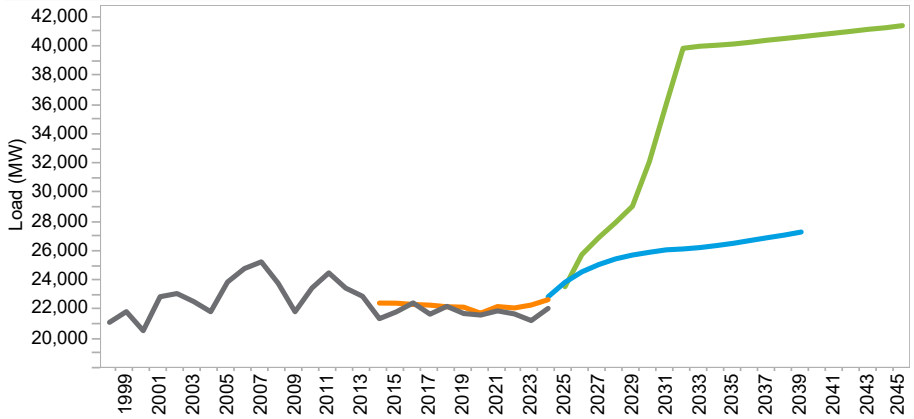
Peak WN peak Forecast 2024 Forecast 2025

MSA

Scranton--Wilkes-Barre--Hazleton, PA

American Electric Power (AEP)

Summer Peak



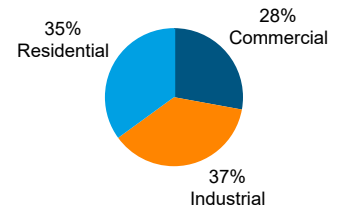
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*73.2*
Avg Summer Max Temp	*92.3*
Avg Winter Daily Temp	*33.4*
Avg Winter Min Temp	*2.9*

Zonal 10/15/20 Year Load Growth

SUMMER	5.5%	3.7%	2.9%
WINTER	5.9%	4.0%	3.1%

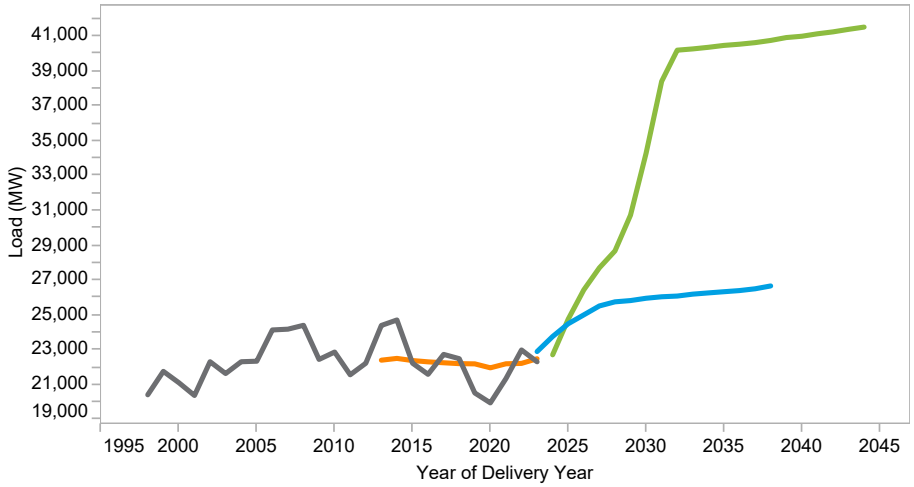
RCI Makeup



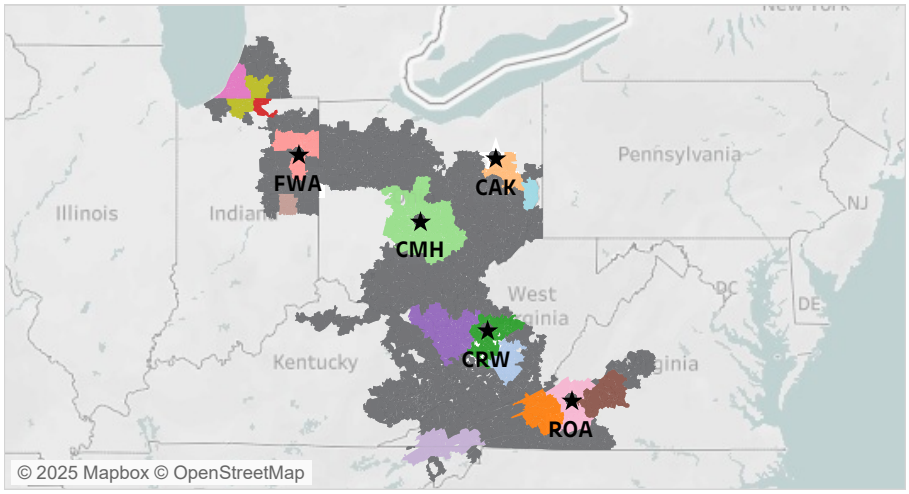
LDAs

PJM RTO PJM WESTERN

Winter Peak



Metropolitan Statistical Areas and Weather Stations



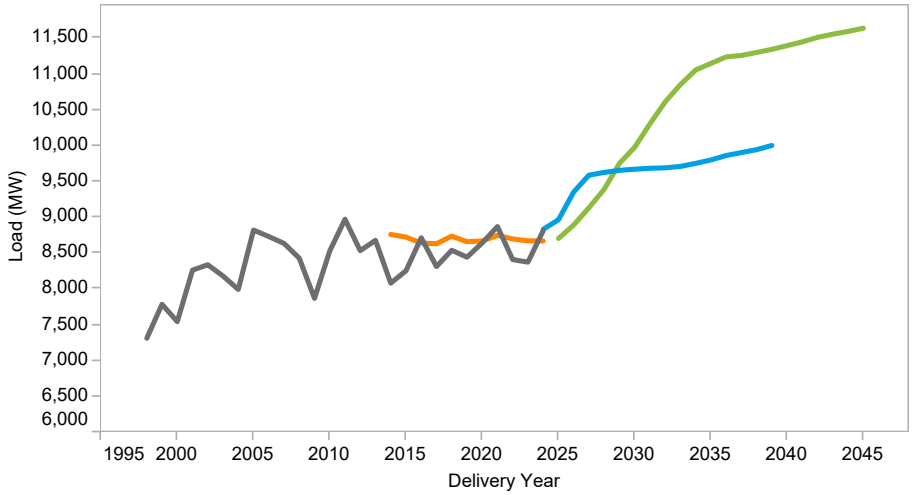
- Peak
- WN peak
- Forecast 2024
- Forecast 2025

MSA

- AEP - Non-Metro
- Beckley, WV
- Blacksburg-Christiansburg-Radford, VA
- Canton-Massillon, OH
- Charleston, WV
- Columbus, OH
- Elkhart-Goshen, IN
- Fort Wayne, IN
- Huntington-Ashland, WV-KY-OH
- Kingsport-Bristol-Bristol, TN-VA
- Lynchburg, VA
- Muncie, IN
- Niles-Benton Harbor, MI
- Roanoke, VA
- South Bend-Mishawaka, IN-MI
- Weirton-Steubenville, WV-OH

Allegheny Power Systems (APS)

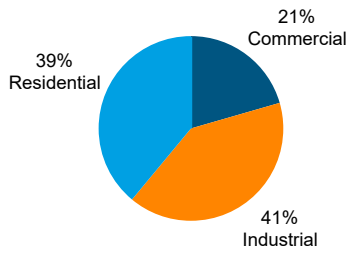
Summer Peak



Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*72.8*
Avg Summer Max Temp	*92.6*
Avg Winter Daily Temp	*33.1*
Avg Winter Min Temp	*2.4*

RCI Makeup



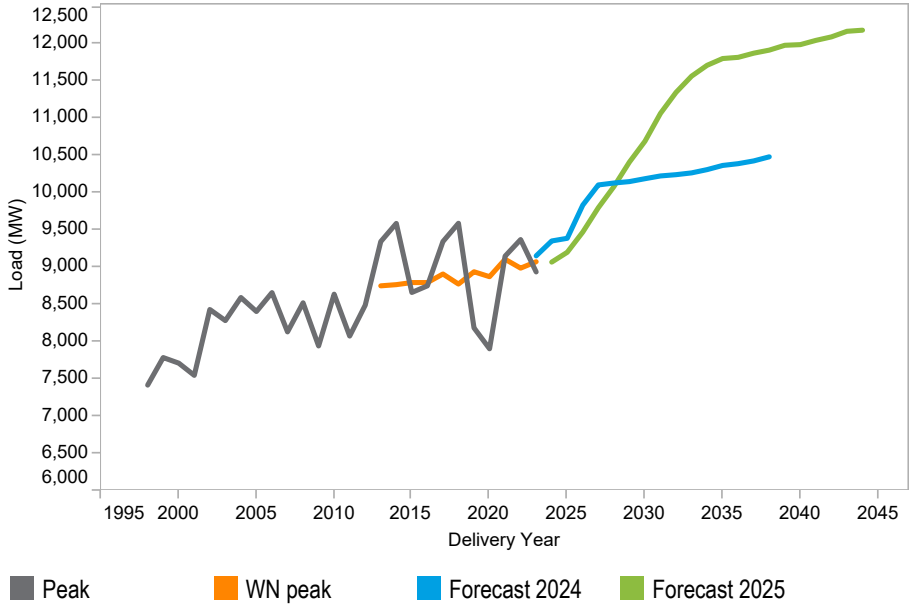
Zonal 10/15/20 Year Load Growth

SUMMER	2.5%	1.8%	1.5%
WINTER	2.6%	1.9%	1.5%

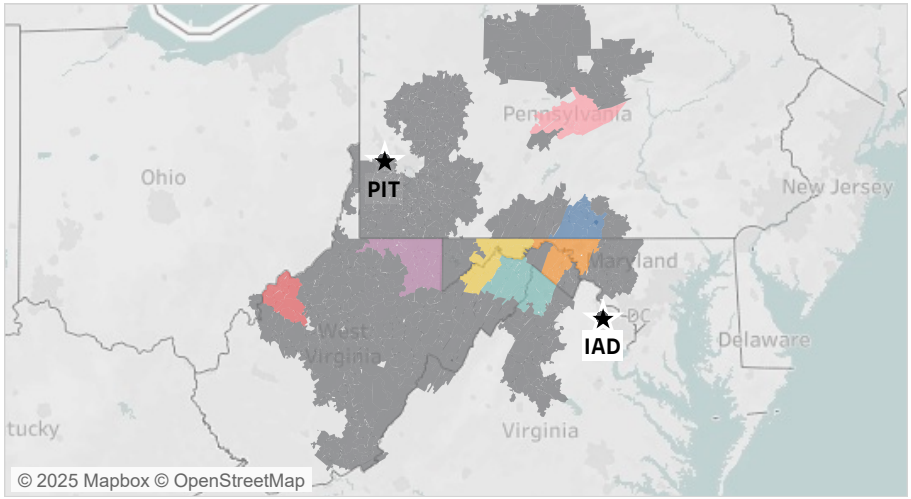
LDAs

PJM RTO PJM WESTERN

Winter Peak



Metropolitan Statistical Areas and Weather Stations

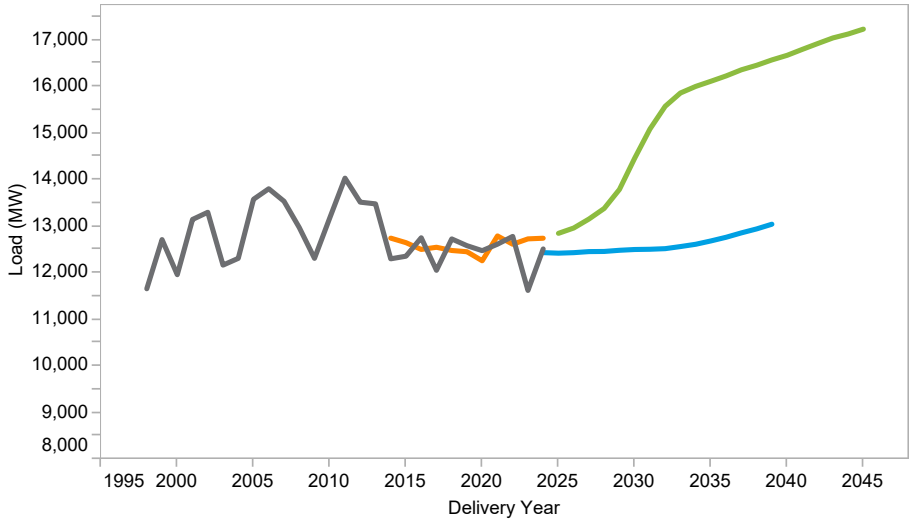


MSA

- APS - Non-metro
- Chambersburg-Waynesboro, PA
- Cumberland, MD-WV
- Hagerstown-Martinsburg, MD-WV
- Morgantown, WV
- Parkersburg-Vienna, WV
- State College, PA
- Winchester, VA-WV

American Transmission Systems, Inc (ATSI)

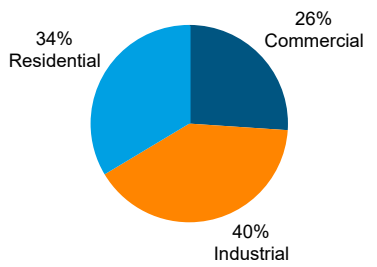
Summer Peak



Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*71.6*
Avg Summer Max Temp	*91.9*
Avg Winter Daily Temp	*30.2*
Avg Winter Min Temp	*-1.0*

RCI Makeup



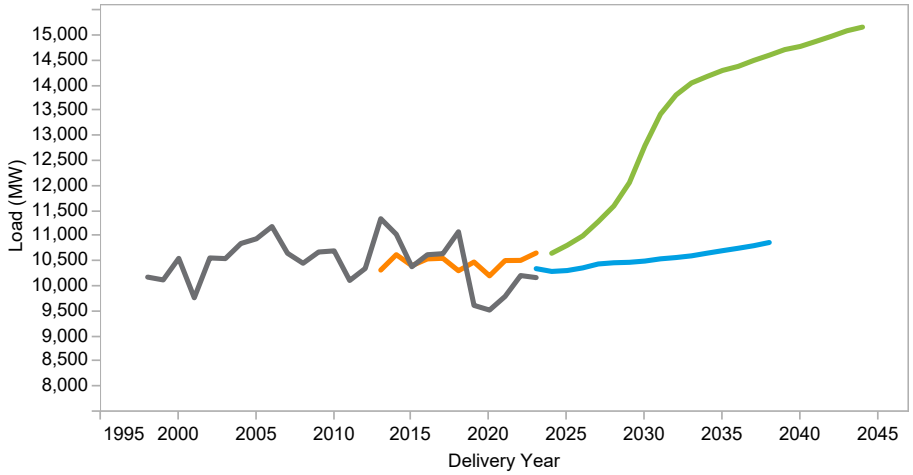
Zonal 10/15/20 Year Load Growth

SUMMER	2.3%	1.8%	1.5%
WINTER	2.9%	2.2%	1.8%

LDAs

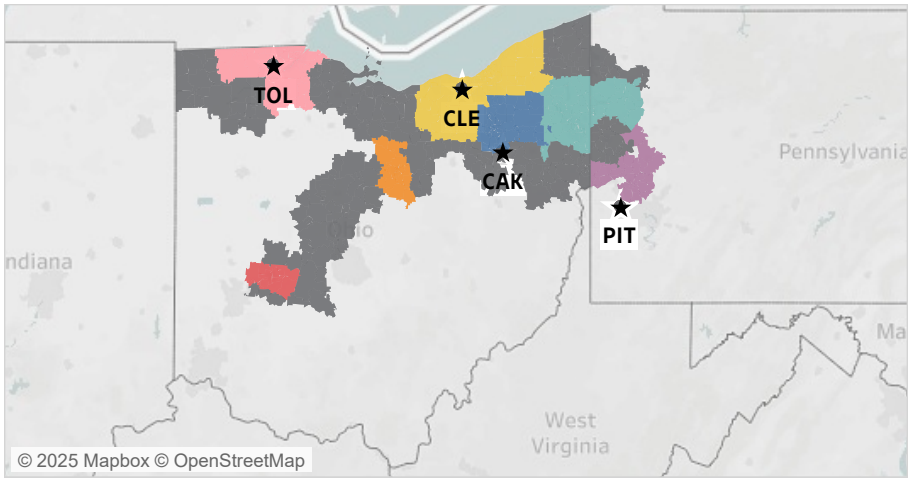
PJM RTO PJM WESTERN

Winter Peak



Peak WN peak Forecast 2024 Forecast 2025

Metropolitan Statistical Areas and Weather Stations

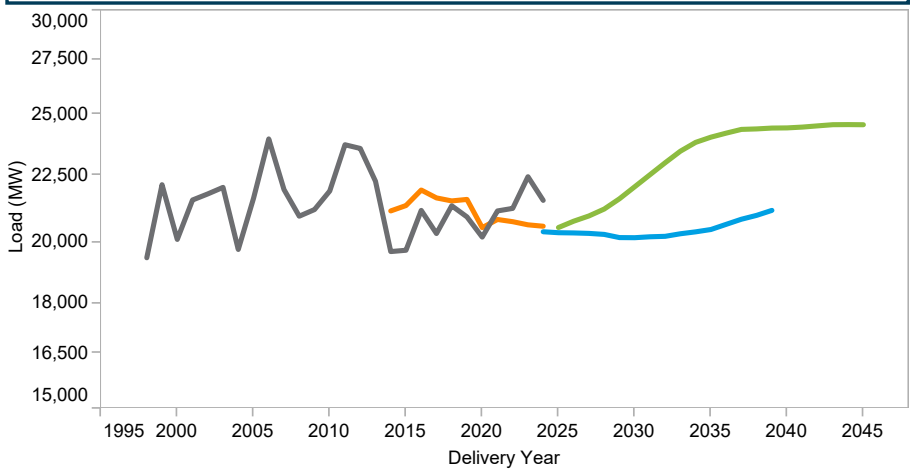


MSA

- Akron, OH
- ATSI - Non-Metro
- Cleveland-Elyria, OH
- Mansfield, OH
- Pittsburgh, PA
- Springfield, OH
- Toledo, OH
- Youngstown-Warren-Boardman, OH-PA

Commonwealth Edison (COMED)

Summer Peak



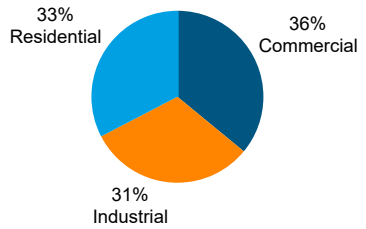
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*73.0*
Avg Summer Max Temp	*95.5*
Avg Winter Daily Temp	*27.8*
Avg Winter Min Temp	*-7.1*

Zonal 10/15/20 Year Load Growth

SUMMER	1.6%	1.2%	0.9%
WINTER	2.9%	2.2%	1.8%

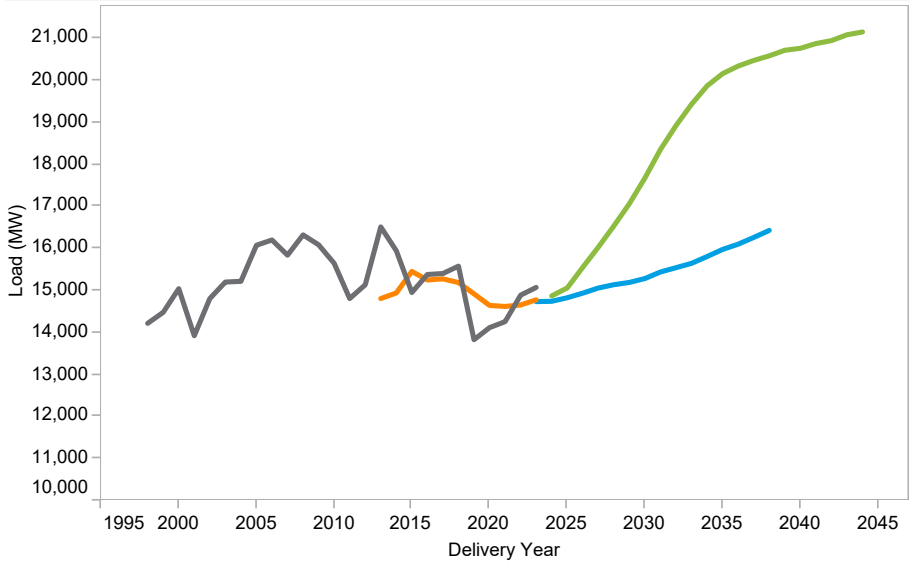
RCI Makeup



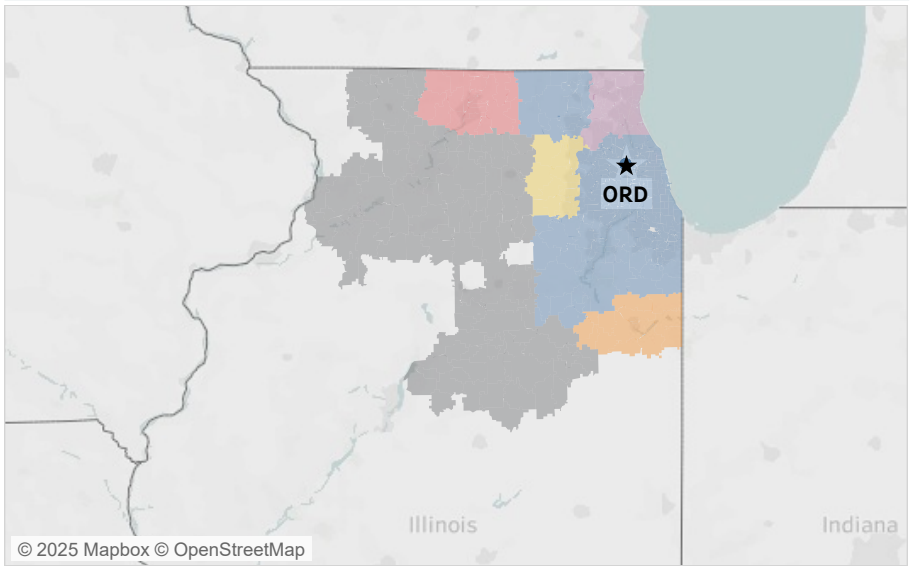
LDAs

PJM RTO PJM WESTERN

Winter Peak



Metropolitan Statistical Areas and Weather Stations

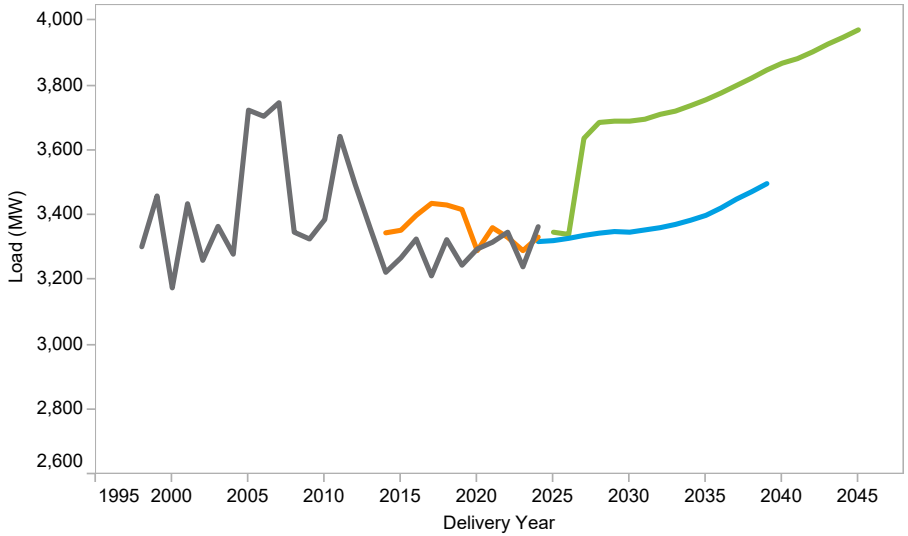


MSA

- Chicago-Naperville-Arlington Heights, IL
- Chicago-Naperville-Elgin, IL-IN-WI
- COMED - Non-Metro
- Kankakee, IL
- Lake County-Kenosha County, IL-WI
- Rockford, IL

Dayton Power and Light (DAYTON)

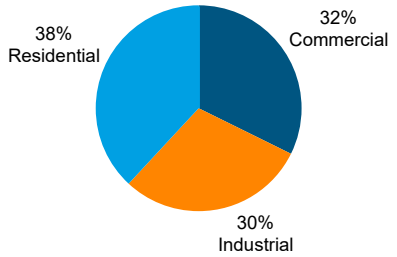
Summer Peak



Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*73.2*
Avg Summer Max Temp	*93.2*
Avg Winter Daily Temp	*31.3*
Avg Winter Min Temp	*-3.0*

RCI Makeup



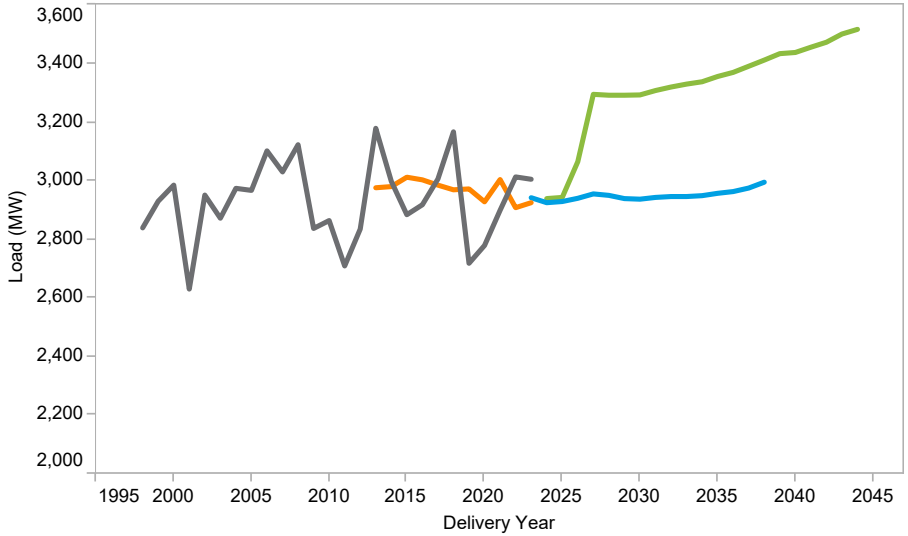
Zonal 10/15/20 Year Load Growth

SUMMER	1.2%	1.0%	0.9%
WINTER	1.3%	1.0%	0.9%

LDAs

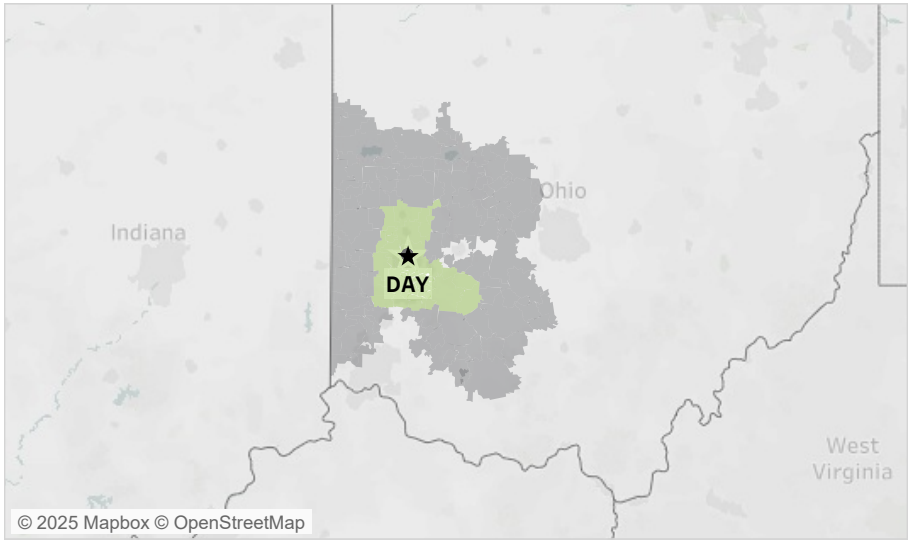
PJM RTO PJM WESTERN

Winter Peak



Peak WN peak Forecast 2024 Forecast 2025

Metropolitan Statistical Areas and Weather Stations



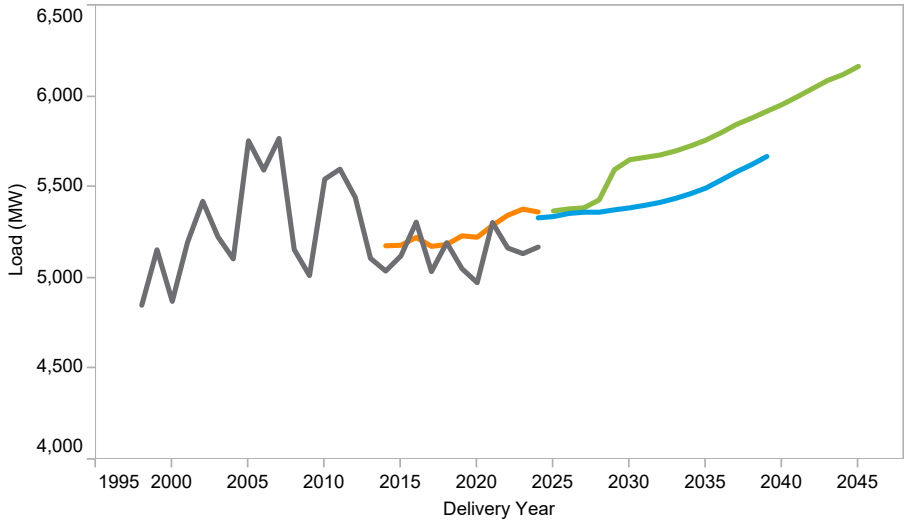
MSA

DAY - Non-Metro

Dayton, OH

Duke Energy Ohio and Kentucky (DEOK)

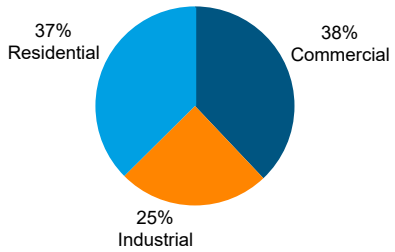
Summer Peak



Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*74.4*
Avg Summer Max Temp	*94.2*
Avg Winter Daily Temp	*34.1*
Avg Winter Min Temp	*-1.1*

RCI Makeup



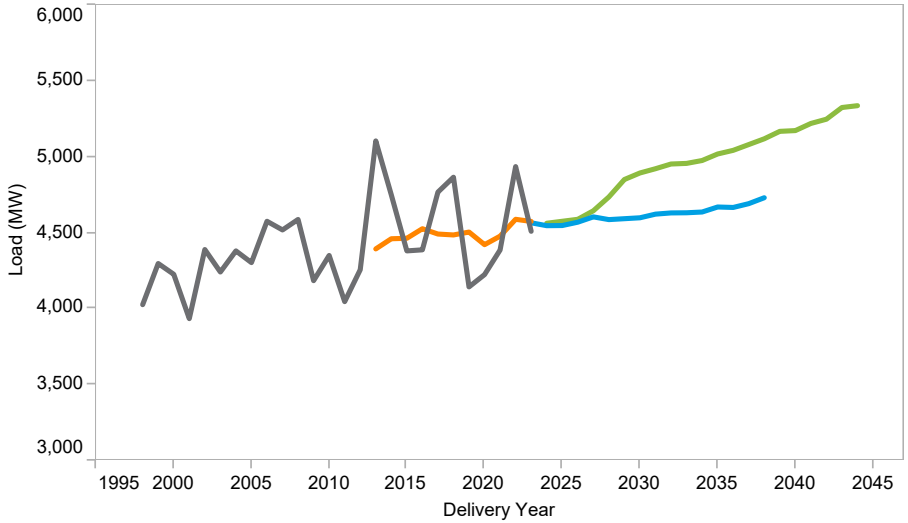
Zonal 10/15/20 Year Load Growth

SUMMER	0.7%	0.7%	0.7%
WINTER	0.9%	0.8%	0.8%

LDAs

PJM RTO PJM WESTERN

Winter Peak



Peak WN peak Forecast 2024 Forecast 2025

Metropolitan Statistical Areas and Weather Stations



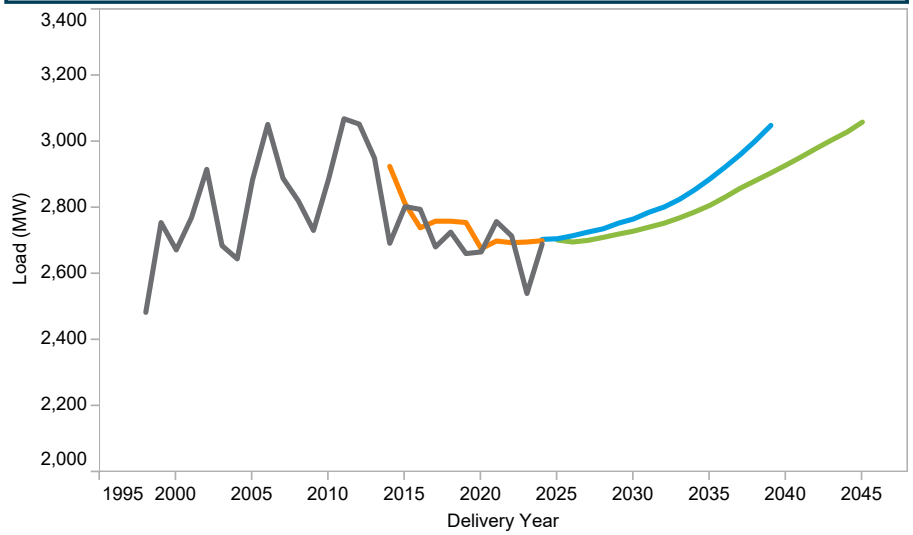
MSA

Cincinnati, OH-KY-IN

DEOK - Non-Metro

Duquesne Light Company (DLCO)

Summer Peak



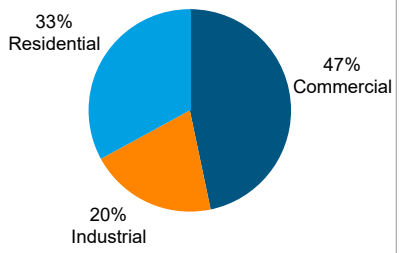
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*71.7*
Avg Summer Max Temp	*91.8*
Avg Winter Daily Temp	*31.7*
Avg Winter Min Temp	*-0.8*

Zonal 10/15/20 Year Load Growth

SUMMER	0.4%	0.5%	0.6%
WINTER	0.7%	0.8%	0.8%

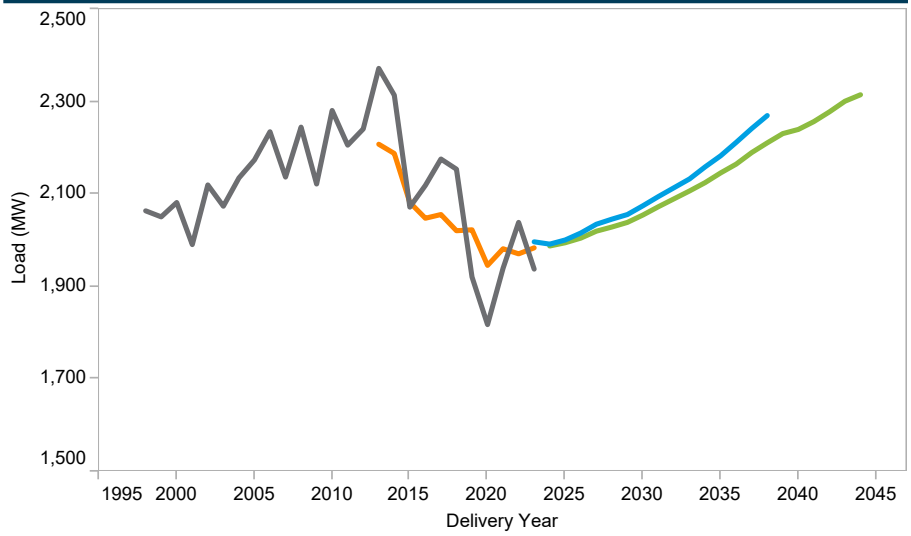
RCI Makeup



LDAs

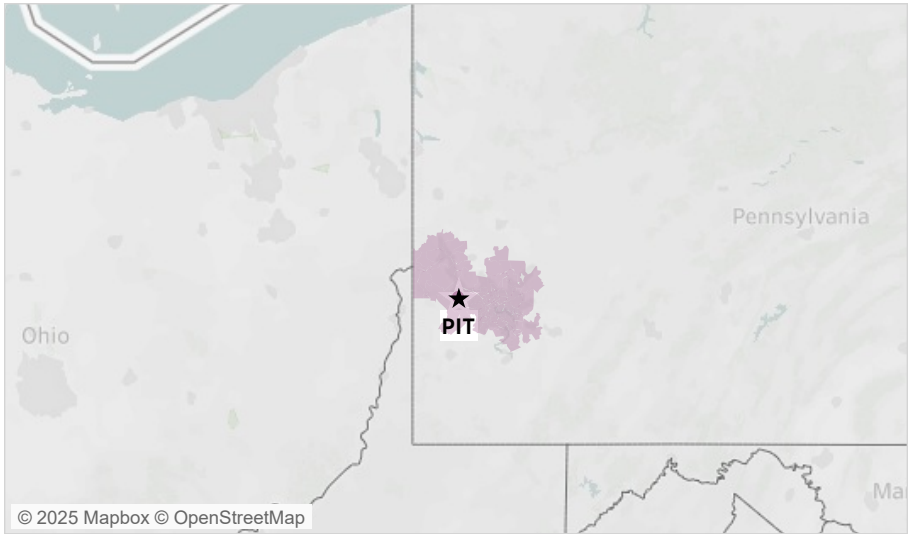
PJM RTO PJM WESTERN

Winter Peak



Peak WN peak Forecast 2024 Forecast 2025

Metropolitan Statistical Areas and Weather Stations

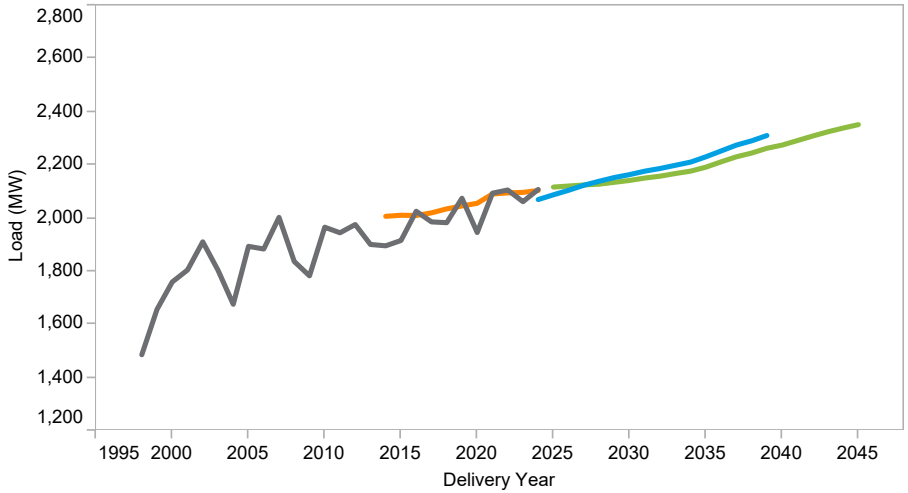


MSA

Pittsburgh, PA

East Kentucky Power Cooperative (EKPC)

Summer Peak



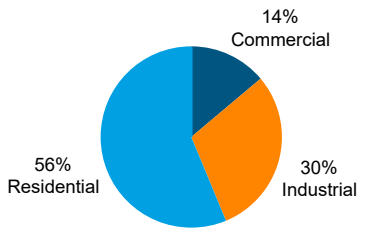
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*75.5*
Avg Summer Max Temp	*94.4*
Avg Winter Daily Temp	*36.1*
Avg Winter Min Temp	*2.4*

Zonal 10/15/20 Year Load Growth

SUMMER	0.3%	0.5%	0.5%
WINTER	0.3%	0.4%	0.4%

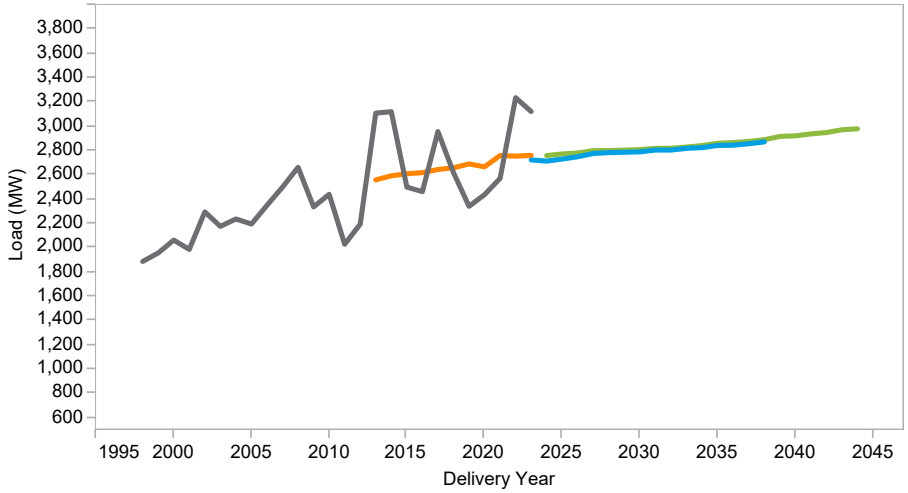
RCI Makeup



LDAs

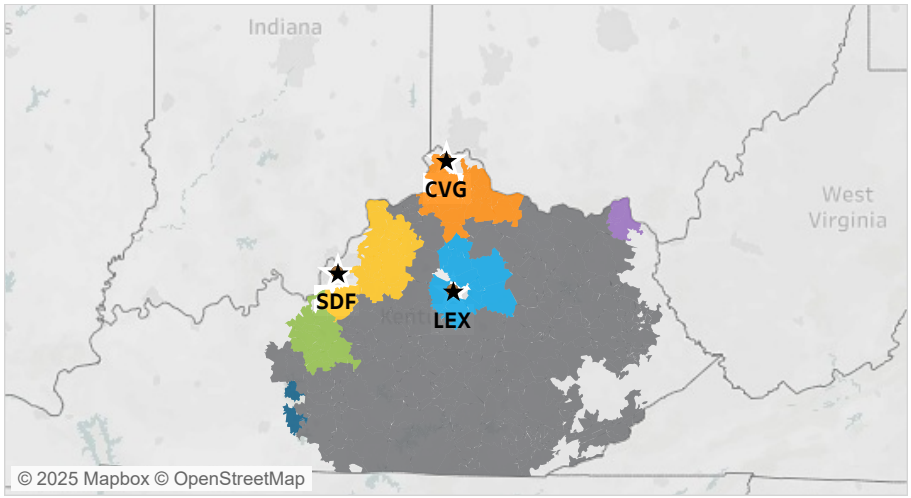
PJM RTO PJM WESTERN

Winter Peak



Peak WN peak Forecast 2024 Forecast 2025

Metropolitan Statistical Areas and Weather Stations

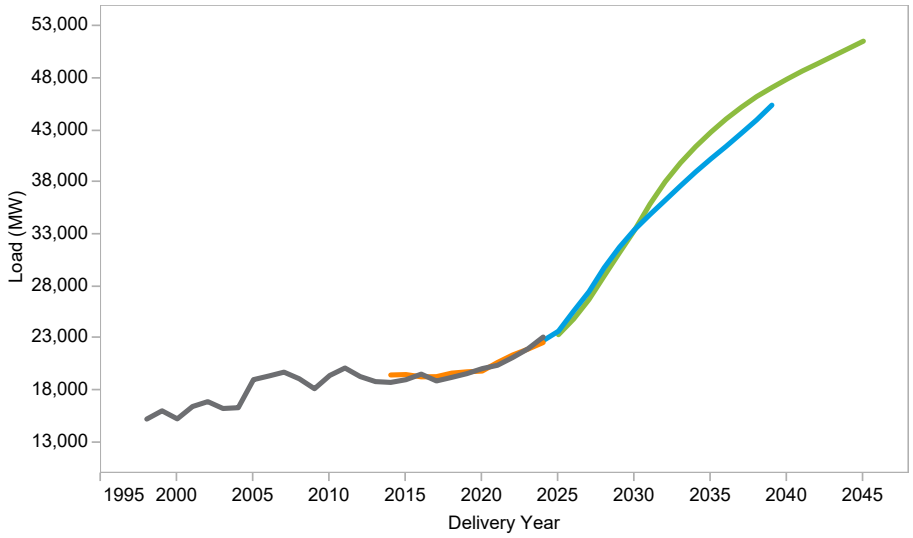


MSA

- Bowling Green, KY
- Cincinnati, OH-KY-IN
- EKPC - Non-Metro
- Elizabethtown-Fort Knox, KY
- Huntington-Ashland, WV-KY-OH
- Lexington-Fayette, KY
- Louisville/Jefferson County, KY-IN

Dominion (DOM)

Summer Peak



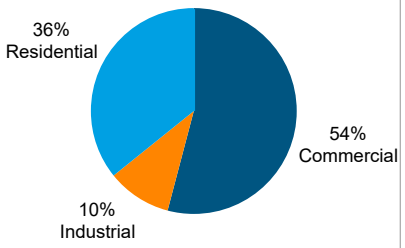
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*77.0*
Avg Summer Max Temp	*97.0*
Avg Winter Daily Temp	*40.5*
Avg Winter Min Temp	*12.4*

Zonal 10/15/20 Year Load Growth

SUMMER	6.3%	4.9%	4.0%
WINTER	6.0%	4.7%	3.9%

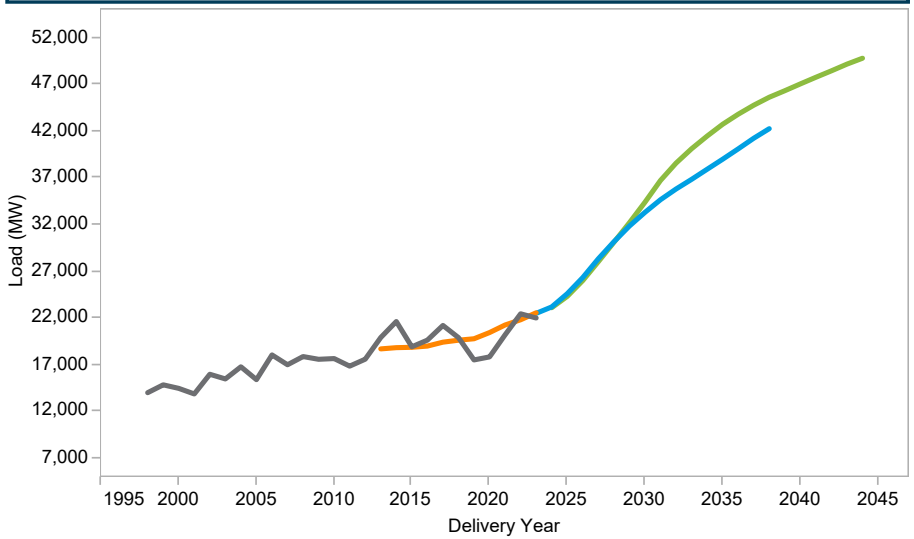
RCI Makeup



LDAs

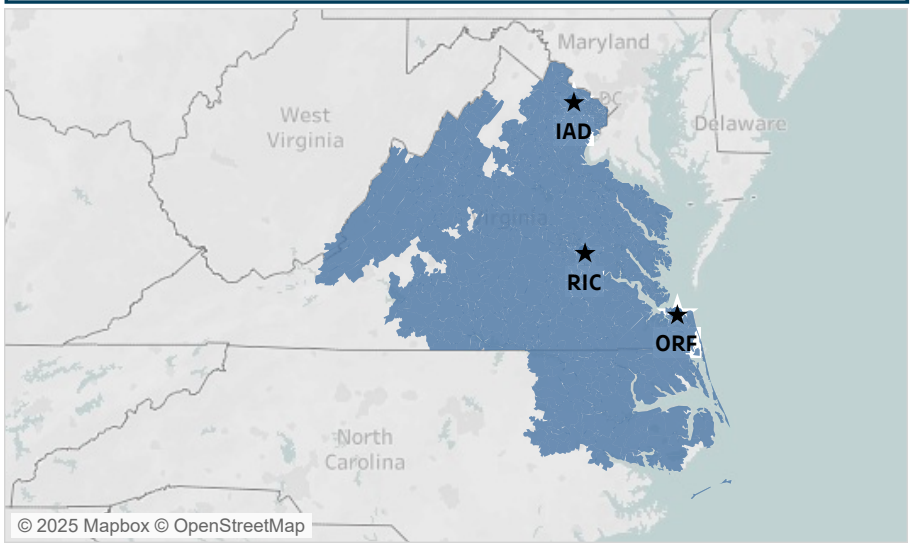
PJM RTO

Winter Peak



Peak WN peak Forecast 2024 Forecast 2025

Metropolitan Statistical Areas and Weather Stations



MSA

Virginia Commonwealth Economics

EXHIBIT NO. 51

SCHEDULE 6 -
REGIONAL TRANSMISSION EXPANSION PLANNING PROTOCOL

References to section numbers in this Schedule 6 refer to sections of this Schedule 6, unless otherwise specified.

1. REGIONAL TRANSMISSION EXPANSION PLANNING PROTOCOL

1.1 Purpose and Objectives.

This Regional Transmission Expansion Planning Protocol shall govern the process by which the Members shall rely upon the Office of the Interconnection to prepare a plan for the enhancement and expansion of the Transmission Facilities in order to meet the demands for firm transmission service, and to support competition, in the PJM Region. The Regional Transmission Expansion Plan (also referred to as "RTEP") to be developed shall enable the transmission needs in the PJM Region to be met on a reliable, economic and environmentally acceptable basis.

1.2 Conformity with NERC *Reliability Standards* and Other Applicable Reliability Criteria.

(a) NERC establishes Reliability Standards to promote the reliability, adequacy and security of the North American bulk power supply as related to the operation and planning of electric systems.

(b) ReliabilityFirst Corporation is responsible for ensuring the reliability, adequacy and security of the bulk electric supply systems in the geographic region described in the applicable agreements between NERC and ReliabilityFirst Corporation, as approved by the FERC, through coordinated operations and planning of generation and transmission facilities. Toward that end, it has adopted the NERC Reliability Standards and has established detailed Reliability Principles and Standards for Planning the Bulk Electric Supply System of the ReliabilityFirst Corporation.

(c) [Reserved]

(c.01) [Reserved]

(c.02) SERC is responsible for ensuring the reliability, adequacy and security of the bulk electric supply systems in the VACAR subregion of SERC. Toward that end, it has adopted the NERC Reliability Standards and has established detailed Reliability Principles and Standards for Planning the Bulk Electric Supply System for SERC.

(d) The Regional Transmission Expansion Plan shall conform at a minimum to the applicable reliability principles, guidelines and standards of NERC, ReliabilityFirst Corporation and SERC, and other Applicable Regional Entities in accordance with the planning and operating criteria and other procedures detailed in the PJM Manuals.

(e) The Regional Transmission Expansion Plan planning criteria shall include, Office of the Interconnection planning procedures, NERC Reliability Standards, Regional Entity reliability principles and standards, and the individual Transmission Owner FERC filed planning criteria as filed in FERC Form No. 715, and posted on the PJM website. FERC Form No. 715 material will be posted to the PJM website, subject to applicable Critical Energy Infrastructure Information (CEII) requirements.

(f) The Office of the Interconnection will also provide access through the PJM website, to the planning criteria and assumptions used by the Transmission Owners for the development of the current Local Plan.

1.3 Establishment of Committees.

(a) The Planning Committee shall be open to participation by (i) all Transmission Customers and applicants for transmission service; (ii) any other entity proposing to provide Transmission Facilities to be integrated into the PJM Region; (iii) all Members; (iv) the electric utility regulatory agencies within the States in the PJM Region and the State Consumer Advocates; and (v) any other interested entities or persons and shall provide technical advice and assistance to the Office of the Interconnection in all aspects of its regional planning functions. The Transmission Owners shall supply representatives to the Planning Committee, and other Members may provide representatives as they deem appropriate, to provide the data, information, and support necessary for the Office of the Interconnection to perform studies as required and to develop the Regional Transmission Expansion Plan.

(b) The Transmission Expansion Advisory Committee established by the Office of the Interconnection will meet periodically with representatives of the Office of the Interconnection to provide advice and recommendations to the Office of the Interconnection to aid in the development of the Regional Transmission Expansion Plan. The Transmission Expansion Advisory Committee participants shall be given an opportunity to provide advice and recommendations for consideration by the Office of the Interconnection regarding sensitivity studies, modeling assumption variations, scenario analyses, and Public Policy Objectives in the studies and analyses to be conducted by the Office of the Interconnection. The Transmission Expansion Advisory Committee participants shall be given the opportunity to review and provide advice and recommendations on the projects to be included in the Regional Transmission Expansion Plan. The Transmission Expansion Advisory Committee meetings shall include discussions addressing interregional planning issues, as required. The Transmission Expansion Advisory Committee shall be open to participation by: (i) all Transmission Customers and applicants for transmission service; (ii) any other entity proposing to provide Transmission Facilities to be integrated into the PJM Region; (iii) all Members; (iv) the electric utility regulatory agencies within the States in the PJM Region, the Independent State Agencies Committee, and the State Consumer Advocates; and (v) any other interested entities or persons. The Transmission Expansion Advisory Committee shall be governed by the Transmission Expansion Advisory Committee rules and procedures set forth in the PJM Regional Planning Process Manual (PJM Manual M-14 series) and by the rules and procedures applicable to PJM committees.

(c) The Subregional RTEP Committees established by the Office of the Interconnection shall facilitate the development and review of the Local Plans. The Subregional RTEP Committees will be responsible for the initial review of the Subregional RTEP Projects, and to provide recommendations to the Transmission Expansion Advisory Committee concerning the Subregional RTEP Projects. A Subregional RTEP Committee may of its own accord or at the request of a Subregional RTEP Committee participant, also refer specific Subregional RTEP Projects to the Transmission Expansion Advisory Committee for further review, advice and recommendations.

(d) The Subregional RTEP Committees shall be responsible for the timely review of the criteria, assumptions and models used to identify reliability criteria violations, economic constraints, or to consider Public Policy Requirements, proposed solutions and written comments prior to finalizing the Local Plan, the coordination and integration of the Local Plans into the RTEP, and addressing any stakeholder issues unresolved in the Local Plan process. The Subregional RTEP Committees will be provided sufficient opportunity to review and provide written comments on the criteria, assumptions, and models used in local planning activities prior to finalizing the Local Plan. The Subregional RTEP Committees shall also be responsible for the timely review of the Transmission Owners' criteria, assumptions, and models used to identify Supplemental Projects that will be considered for inclusion in the Local Plan for each Subregional RTEP Committee. The Subregional RTEP Committees meetings shall include discussions addressing interregional planning issues, as required. Once finalized, the Subregional RTEP Committees will be provided sufficient opportunity to review and provide written comments on the Local Plans as integrated into the RTEP, prior to the submittal of the final Regional Transmission Expansion Plan to the PJM Board for approval. In addition, the Subregional RTEP Committees will provide sufficient opportunity to review and provide written comments to the Transmission Owners on any Supplemental Projects included in the Local Plan, in accordance with Additional Procedures for Planning of Supplemental Projects set forth in Tariff, Attachment M-3.

(e) The Subregional RTEP Committees shall be open to participation by: (i) all Transmission Customers and applicants for transmission service; (ii) any other entity proposing to provide Transmission Facilities to be integrated into the PJM Region; (iii) all Members; (iv) the electric utility regulatory agencies within the States in the PJM Region, the Independent State Agencies Committee, and the State Consumer Advocates and (v) any other interested entities or persons.

(f) Each Subregional RTEP Committee shall schedule and facilitate a minimum of one Subregional RTEP Committee meeting to review the criteria, assumptions and models to identify reliability criteria violations, economic constraints, or to consider Public Policy Requirements. Each Subregional RTEP Committee shall schedule and facilitate an additional Subregional RTEP Committee meeting, per planning cycle, and as required to review the identified criteria violations and potential solutions. The Subregional RTEP Committees may facilitate additional meetings to incorporate more localized areas in the subregional planning process. At the discretion of the Office of the Interconnection, a designated Transmission Owner may facilitate Subregional RTEP Committee meeting(s), or the additional meetings incorporating the more localized areas.

(g) The Subregional RTEP Committees shall schedule and facilitate meetings regarding Supplemental Projects, as described in the Tariff, Attachment M-3.

(h) The Subregional RTEP Committees shall be governed by the Transmission Expansion Advisory Committee rules and procedures set forth in the PJM Regional

Planning Process Manual (Manual M-14 series) and by the rules and procedures applicable to PJM committees.

1.4 Contents of the Regional Transmission Expansion Plan.

(a) The Regional Transmission Expansion Plan shall consolidate the transmission needs of the region into a single plan which is assessed on the bases of (i) maintaining the reliability of the PJM Region in an economic and environmentally acceptable manner, (ii) supporting competition in the PJM Region, (iii) striving to maintain and enhance the market efficiency and operational performance of wholesale electric service markets and (iv) considering federal and state Public Policy Requirements.

(b) The Regional Transmission Expansion Plan shall reflect, consistent with the requirements of this Schedule 6, transmission enhancements and expansions; load forecasts; and capacity forecasts, including expected generation additions and retirements, demand response, and reductions in demand from energy efficiency and price responsive demand for at least the ensuing ten years.

(c) The Regional Transmission Expansion Plan shall, at a minimum, include a designation of the Transmission Owner(s) or other entity(ies) that will construct, own, maintain, operate, and/or finance each transmission enhancement and expansion and how all reasonably incurred costs are to be recovered.

(d) The Regional Transmission Expansion Plan shall (i) avoid unnecessary duplication of facilities; (ii) avoid the imposition of unreasonable costs on any Transmission Owner or any user of Transmission Facilities; (iii) take into account the legal and contractual rights and obligations of the Transmission Owners; (iv) provide, if appropriate, alternative means for meeting transmission needs in the PJM Region; (v) provide for coordination with existing transmission systems and with appropriate interregional and local expansion plans; and (vi) strive for consistency in planning data and assumptions that may relieve transmission congestion across multiple regions.

1.5 Procedure for Development of the Regional Transmission Expansion Plan.

1.5.1 Commencement of the Process.

(a) The Office of the Interconnection shall initiate the enhancement and expansion study process if: (i) required as a result of a need for transfer capability identified by the Office of the Interconnection in its evaluation of requests for interconnection with the Transmission System or for firm transmission service with a term of one year or more; (ii) required to address a need identified by the Office of the Interconnection in its on-going evaluation of the Transmission System's market efficiency and operational performance; (iii) required as a result of the Office of the Interconnection's assessment of the Transmission System's compliance with NERC Reliability Standards, more stringent reliability criteria, if any, or PJM planning and operating criteria; (iv) required to address constraints or available transfer capability shortages, including, but not limited to, available transfer capability shortages that prevent the simultaneous feasibility of stage 1A Auction Revenue Rights allocated pursuant to the Operating Agreement, Schedule 1, section 7.4.2(b), constraints or shortages as a result of expected generation retirements, constraints or shortages based on an evaluation of load forecasts, or system reliability needs arising from proposals for the addition of Transmission Facilities in the PJM Region; or (v) expansion of the Transmission System is proposed by one or more Transmission Owners, Interconnection Customers, Network Service Users or Transmission Customers, or any party that funds Network Upgrades pursuant to the Operating Agreement, Schedule 1, section 7.8. The Office of the Interconnection may initiate the enhancement and expansion study process to address or consider, where appropriate, requirements or needs arising from sensitivity studies, modeling assumption variations, scenario analyses, and Public Policy Objectives.

(b) The Office of the Interconnection shall notify the Transmission Expansion Advisory Committee participants of, as well as publicly notice, the commencement of an enhancement and expansion study. The Transmission Expansion Advisory Committee participants shall notify the Office of the Interconnection in writing of any additional transmission considerations they would like to have included in the Office of the Interconnection's analyses.

1.5.2 Development of Scope, Assumptions and Procedures.

Once the need for an enhancement and expansion study has been established, the Office of the Interconnection shall consult with the Transmission Expansion Advisory Committee and the Subregional RTEP Committees, as appropriate, to prepare the study's scope, assumptions and procedures.

1.5.3 Scope of Studies.

In conducting the enhancement and expansion studies, the Office of the Interconnection shall not limit its analyses to bright line tests to identify and evaluate potential Transmission System limitations, violations of planning criteria, or transmission needs. In addition to the bright line tests, the Office of the Interconnection shall employ sensitivity studies, modeling assumption variations, and scenario analyses, and shall also consider Public Policy Objectives in the studies and analyses, so as to mitigate the possibility that bright line metrics may inappropriately include

or exclude transmission projects from the transmission plan. Sensitivity studies, modeling assumption variations, and scenario analyses shall take account of potential changes in expected future system conditions, including, but not limited to, load levels, transfer levels, fuel costs, the level and type of generation, generation patterns (including, but not limited to, the effects of assumptions regarding generation that is at risk for retirement and new generation to satisfy Public Policy Objectives), demand response, and uncertainties arising from estimated times to construct transmission upgrades. The Office of the Interconnection shall use the sensitivity studies, modeling assumption variations and scenario analyses in evaluating and choosing among alternative solutions to reliability, market efficiency and operational performance needs. The Office of the Interconnection shall provide the results of its studies and analyses to the Transmission Expansion Advisory Committee to consider the impact that sensitivities, assumptions, and scenarios may have on Transmission System needs and the need for transmission enhancements or expansions. Enhancement and expansion studies shall be completed by the Office of the Interconnection in collaboration with the affected Transmission Owners, as required. In general, enhancement and expansion studies shall include:

(a) An identification of existing and projected limitations on the Transmission System's physical, economic and/or operational capability or performance, with accompanying simulations to identify the costs of controlling those limitations. Potential enhancements and expansions will be proposed to mitigate limitations controlled by non-economic means.

(b) Evaluation and analysis of potential enhancements and expansions, including alternatives thereto, needed to mitigate such limitations.

(c) Identification, evaluation and analysis of potential transmission expansions and enhancements, demand response programs, and other alternative technologies as appropriate to maintain system reliability.

(d) Identification, evaluation and analysis of potential enhancements and expansions for the purposes of supporting competition, market efficiency, operational performance, and Public Policy Requirements in the PJM Region.

(e) Identification, evaluation and analysis of upgrades to support Incremental Auction Revenue Rights requested pursuant to the Operating Agreement, Schedule 1, section 7.8.

(f) Identification, evaluation and analysis of upgrades to support all transmission customers, including native load and network service customers.

(g) Engineering studies needed to determine the effectiveness and compliance of recommended enhancements and expansions, with the following PJM criteria: system reliability, operational performance, and market efficiency.

(h) Identification, evaluation and analysis of potential enhancements and expansions designed to ensure that the Transmission System's capability can support the simultaneous feasibility of all stage 1A Auction Revenue Rights allocated pursuant to the Operating Agreement, Schedule 1, section 7.4.2(b). Enhancements and expansions related to stage 1A

Auction Revenue Rights identified pursuant to this Section shall be recommended for inclusion in the Regional Transmission Expansion Plan together with a recommended in-service date based on the results of the ten (10) year stage 1A simultaneous feasibility analysis. Any such recommended enhancement or expansion under this Operating Agreement, Schedule 6, section 1.5.3(h) shall include, but shall not be limited to, the reason for the upgrade, the cost of the upgrade, the cost allocation identified pursuant to the Operating Agreement, Schedule 6, section 1.5.6(m) and an analysis of the benefits of the enhancement or expansion, provided that any such upgrades will not be subject to a market efficiency cost/benefit analysis.

1.5.4 Supply of Data.

(a) The Transmission Owners shall provide to the Office of the Interconnection on an annual or periodic basis as specified by the Office of the Interconnection, any information and data reasonably required by the Office of the Interconnection to perform the Regional Transmission Expansion Plan, including but not limited to the following: (i) a description of the total load to be served from each substation; (ii) the amount of any interruptible loads included in the total load (including conditions under which an interruption can be implemented and any limitations on the duration and frequency of interruptions); (iii) a description of all generation resources to be located in the geographic region encompassed by the Transmission Owner's transmission facilities, including unit sizes, VAR capability, operating restrictions, and any must-run unit designations required for system reliability or contract reasons; the (iv) current local planning information, including all criteria, assumptions and models used by the Transmission Owners, such as those used to develop Supplemental Projects. The data required under this Section shall be provided in the form and manner specified by the Office of the Interconnection.

(b) In addition to the foregoing, the Transmission Owners, those entities requesting transmission service and any other entities proposing to provide Transmission Facilities to be integrated into the PJM Region shall supply any other information and data reasonably required by the Office of the Interconnection to perform the enhancement and expansion study.

(c) The Office of the Interconnection also shall solicit from the Members, Transmission Customers and other interested parties, including but not limited to electric utility regulatory agencies within the States in the PJM Region, Independent State Agencies Committee, and the State Consumer Advocates, information required by, or anticipated to be useful to, the Office of the Interconnection in its preparation of the enhancement and expansion study, including information regarding potential sensitivity studies, modeling assumption variations, scenario analyses, and Public Policy Objectives that may be considered.

(d) The Office of the Interconnection shall supply to the Transmission Expansion Advisory Committee and the Subregional RTEP Committees reasonably required information and data utilized to develop the Regional Transmission Expansion Plan. Such information and data shall be provided pursuant to the appropriate protection of confidentiality provisions and Office of the Interconnection's CEII process.

(e) The Office of the Interconnection shall provide access through the PJM website, to the Transmission Owner's local planning information, including all criteria, assumptions and models

used by the Transmission Owners in their internal planning processes, including the development of Supplemental Projects ("Local Plan Information"). Local Plan Information shall be provided consistent with: (1) any applicable confidentiality provisions set forth in the Operating Agreement, section 18.17; (2) the Office of the Interconnection's CEII process; and (3) any applicable copyright limitations. Notwithstanding the foregoing, the Office of the Interconnection may share with a third party Local Plan Information that has been designated as confidential, pursuant to the provisions for such designation as set forth in the Operating Agreement, section 18.17 and subject to: (i) agreement by the disclosing Transmission Owner consistent with the process set forth in this Operating Agreement; and (ii) an appropriate non-disclosure agreement to be executed by PJM Interconnection, L.L.C., the Transmission Owner and the requesting third party. With the exception of confidential, CEII and copyright protected information, Local Plan Information will be provided for full review by the Planning Committee, the Transmission Expansion Advisory Committee, and the Subregional RTEP Committees.

1.5.5 Coordination of the Regional Transmission Expansion Plan.

(a) The Regional Transmission Expansion Plan shall be developed in accordance with the principles of interregional coordination with the Transmission Systems of the surrounding Regional Entities and with the local transmission providers, through the Transmission Expansion Advisory Committee and the Subregional RTEP Committee.

(b) The Regional Transmission Expansion Plan shall be developed taking into account the processes for coordinated regional transmission expansion planning established under the following agreements:

- Joint Operating Agreement Between the Midwest Independent System Operator, Inc. and PJM Interconnection, L.L.C., which is found at http://www.pjm.com/~/media/documents/agreements/joa-complete.ashx;

- Northeastern ISO/RTO Planning Coordination Protocol, which is described at Schedule 6-B and found at http://www.pjm.com/~/media/documents/agreements/northeastern-iso-rto-planning-coordination-protocol.ashx;

- Joint Operating Agreement Among and Between New York Independent System Operator Inc., which is found at http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx;

- Interregional Transmission Coordination Between the SERTP and PJM Regions, which is found at Operating Agreement, Schedule 6-A ;

- Allocation of Costs of Certain Interregional Transmission Projects Located in the PJM and SERTP Regions, which is located at Tariff, Schedule 12-B;

- Joint Reliability Coordination Agreement Between PJM Interconnection, L.L.C., Tennessee Valley Authority, and Louisville Gas and Electric Company and Kentucky Utilities.

(i) Coordinated regional transmission expansion planning shall also incorporate input from parties that may be impacted by the coordination efforts, including but not limited to, the Members, Transmission Customers, electric utility regulatory agencies in the PJM Region, and the State Consumer Advocates, in accordance with the terms and conditions of the applicable regional coordination agreements.

(ii) An entity, including existing Transmission Owners and Nonincumbent Developers, may submit potential Interregional Transmission Projects pursuant to the Operating Agreement, Schedule 6, section 1.5.8.

(c) The Regional Transmission Expansion Plan shall be developed by the Office of the Interconnection in consultation with the Transmission Expansion Advisory Committee during the enhancement and expansion study process.

(d) The Regional Transmission Expansion Plan shall be developed taking into account the processes for coordination of the regional and subregional systems.

1.5.6 Development of the Recommended Regional Transmission Expansion Plan.

(a) The Office of the Interconnection shall be responsible for the development of the Regional Transmission Expansion Plan and for conducting the studies, including sensitivity studies and scenario analyses on which the plan is based. The Regional Transmission Expansion Plan, including the Regional RTEP Projects, the Subregional RTEP Projects and the Supplemental Projects shall be developed through an open and collaborative process with opportunity for meaningful participation through the Transmission Expansion Advisory Committee and the Subregional RTEP Committees.

(b) The Transmission Expansion Advisory Committee and the Subregional RTEP Committees shall each facilitate a minimum of one initial assumptions meeting to be scheduled at the commencement of the Regional Transmission Expansion Plan process. The purpose of the assumptions meeting shall be to provide an open forum to discuss the following: (i) the assumptions to be used in performing the evaluation and analysis of the potential enhancements and expansions to the Transmission Facilities; (ii) Public Policy Requirements identified by the states for consideration in the Office of the Interconnection's transmission planning analyses; (iii) Public Policy Objectives identified by stakeholders for consideration in the Office of the Interconnection's transmission planning analyses; (iv) the impacts of regulatory actions, projected changes in load growth, demand response resources, energy efficiency programs, price responsive demand, generating additions and retirements, market efficiency and other trends in the industry; and (v) alternative sensitivity studies, modeling assumptions and scenario analyses proposed by the Committee participants. Prior to the initial assumptions meeting, the Transmission Expansion Advisory Committee and Subregional RTEP Committees participants will be afforded the opportunity to provide input and submit suggestions regarding the information identified in items (i) through (v) of this subsection. Following the assumptions meeting and prior to performing the evaluation and analyses of transmission needs, the Office of the Interconnection shall determine the range of assumptions to be used in the studies and

scenario analyses, based on the advice and recommendations of the Transmission Expansion Advisory Committee and Subregional RTEP Committees and, through the Independent State Agencies, the statement of Public Policy Requirements provided individually by the states and any state member's assessment or prioritization of Public Policy Objectives proposed by other stakeholders. The Office of the Interconnection shall document and publicly post its determination for review. Such posting shall include an explanation of those Public Policy Requirements and Public Policy Objectives adopted at the assumptions stage to be used in performing the evaluation and analysis of transmission needs. Following identification of transmission needs and prior to evaluating potential enhancements and expansions to the Transmission System the Office of the Interconnection shall publicly post all transmission need information identified as described further in the Operating Agreement, Schedule 6, section 1.5.8(b) herein to support the role of the Subregional RTEP Committees in the development of the Local Plan and support the role of Transmission Expansion Advisory Committee in the development of the Regional Transmission Expansion Plan. The Office of the Interconnection shall also post an explanation of why other Public Policy Requirements and Public Policy Objectives introduced by stakeholders at the assumptions stage were not adopted.

(c) The Subregional RTEP Committees shall also schedule and facilitate meetings related to Supplemental Projects, as described in the Tariff, Attachment M-3.

(d) After the assumptions meeting(s), the Transmission Expansion Advisory Committee and the Subregional RTEP Committees shall facilitate additional meetings and shall post all communications required to provide early opportunity for the committee participants (as defined in the Operating Agreement, Schedule 6, sections 1.3(b) and 1.3(c)) to review, evaluate and offer comments and alternatives to the following arising from the studies performed by the Office of the Interconnection, including sensitivity studies and scenario analyses: (i) any identified violations of reliability criteria and analyses of the market efficiency and operational performance of the Transmission System; (ii) potential transmission solutions, including any acceleration, deceleration or modifications of a potential expansion or enhancement based on the results of sensitivities studies and scenario analyses; and (iii) the proposed Regional Transmission Expansion Plan. These meetings will be scheduled as deemed necessary by the Office of the Interconnection or upon the request of the Transmission Expansion Advisory Committee or the Subregional RTEP Committees. The Office of the Interconnection will provide updates on the status of the development of the Regional Transmission Expansion Plan at these meetings or at the regularly scheduled meetings of the Planning Committee.

(e) In addition, the Office of the Interconnection shall facilitate periodic meetings with the Independent State Agencies Committee to discuss: (i) the assumptions to be used in performing the evaluation and analysis of the potential enhancements and expansions to the Transmission Facilities; (ii) regulatory initiatives, as appropriate, including state regulatory agency initiated programs, and other Public Policy Objectives, to consider including in the Office of the Interconnection's transmission planning analyses; (iii) the impacts of regulatory actions, projected changes in load growth, demand response resources, energy efficiency programs, generating capacity, market efficiency and other trends in the industry; and (iv) alternative sensitivity studies, modeling assumptions and scenario analyses proposed by Independent State Agencies Committee. At such meetings, the Office of the Interconnection also shall discuss the

current status of the enhancement and expansion study process. The Independent State Agencies Committee may request that the Office of Interconnection schedule additional meetings as necessary. The Office of the Interconnection shall inform the Transmission Expansion Advisory Committee and the Subregional RTEP Committees, as appropriate, of the input of the Independent State Agencies Committee and shall consider such input in developing the range of assumptions to be used in the studies and scenario analyses described in section (b), above.

(f) Upon completion of its studies and analysis, including sensitivity studies and scenario analyses the Office of the Interconnection shall post on the PJM website the violations, system conditions, economic constraints, and Public Policy Requirements as detailed in the Operating Agreement, Schedule 6, section 1.5.8(b) to afford entities an opportunity to submit proposed enhancements or expansions to address the posted violations, system conditions, economic constraints and Public Policy Requirements as provided for in the Operating Agreement, Schedule 6, section 1.5.8(c). Following the close of a proposal window, the Office of the Interconnection shall: (i) post all proposals submitted pursuant to the Operating Agreement, Schedule 6, section 1.5.8(c); (ii) consider proposals submitted during the proposal windows consistent with the Operating Agreement, Schedule 6, section 1.5.8(d) and develop a recommended plan. Following review by the Transmission Expansion Advisory Committee of proposals, the Office of the Interconnection, based on identified needs and the timing of such needs, and taking into account the sensitivity studies, modeling assumption variations and scenario analyses considered pursuant to the Operating Agreement, Schedule 6, section 1.5.3, shall determine, which more efficient or cost-effective enhancements and expansions shall be included in the recommended plan, including solutions identified as a result of the sensitivity studies, modeling assumption variations, and scenario analyses, that may accelerate, decelerate or modify a potential reliability, market efficiency or operational performance expansion or enhancement identified as a result of the sensitivity studies, modeling assumption variations and scenario analyses, shall be included in the recommended plan. The Office of the Interconnection shall post the proposed recommended plan for review and comment by the Transmission Expansion Advisory Committee. The Transmission Expansion Advisory Committee shall facilitate open meetings and communications as necessary to provide opportunity for the Transmission Expansion Advisory Committee participants to collaborate on the preparation of the recommended enhancement and expansion plan. The Office of the Interconnection also shall invite interested parties to submit comments on the plan to the Transmission Expansion Advisory Committee and to the Office of the Interconnection before submitting the recommended plan to the PJM Board for approval.

(g) The recommended plan shall separately identify enhancements and expansions for the three PJM subregions, the PJM Mid-Atlantic Region, the PJM West Region, and the PJM South Region, and shall incorporate recommendations from the Subregional RTEP Committees.

(h) The recommended plan shall separately identify enhancements and expansions that are classified as Supplemental Projects.

(i) The recommended plan shall identify enhancements and expansions that relieve transmission constraints and which, in the judgment of the Office of the Interconnection, are economically justified. Such economic expansions and enhancements shall be developed in

accordance with the procedures, criteria and analyses described in the Operating Agreement, Schedule 6, sections 1.5.7 and 1.5.8.

(j) The recommended plan shall identify enhancements and expansions proposed by a state or states pursuant to the Operating Agreement, Schedule 6, section 1.5.9.

(k) The recommended plan shall include proposed Merchant Transmission Facilities within the PJM Region and any other enhancement or expansion of the Transmission System requested by any participant which the Office of the Interconnection finds to be compatible with the Transmission System, though not required pursuant to the Operating Agreement, Schedule 6, 1.5.6, or Tariff Parts VII or VIII, provided that (1) the requestor has complied, to the extent applicable, with the procedures and other requirements of the Tariff, Parts IV and VI, or Tariff, Parts VII or VIII, as applicable; (2) the proposed enhancement or expansion is consistent with applicable reliability standards, operating criteria and the purposes and objectives of the regional planning protocol; (3) the requestor shall be responsible for all costs of such enhancement or expansion (including, but not necessarily limited to, costs of siting, designing, financing, constructing, operating and maintaining the pertinent facilities), and (4) except as otherwise provided by the Tariff, Parts IV and VI, , or Tariff, Parts VII or VIII, as applicable with respect to Merchant Network Upgrades, the requestor shall accept responsibility for ownership, construction, operation and maintenance of the enhancement or expansion through an undertaking satisfactory to the Office of the Interconnection.

(l) For each enhancement or expansion that is included in the recommended plan, the plan shall consider, based on the planning analysis: other input from participants, including any indications of a willingness to bear cost responsibility for such enhancement or expansion; and, when applicable, relevant projects being undertaken to ensure the simultaneous feasibility of Stage 1A ARRs, to facilitate Incremental ARRs pursuant to the provisions of the Operating Agreement, Schedule 1, section 7.8, or to facilitate upgrades pursuant to the Tariff, Parts II, III, or VI, or Tariff, Parts VII or VIII, as applicable and designate one or more Transmission Owners or other entities to construct, own and, unless otherwise provided, finance the recommended transmission enhancement or expansion. Any designation under this paragraph of one or more entities to construct, own and/or finance a recommended transmission enhancement or expansion shall also include a designation of partial responsibility among them. Nothing herein shall prevent any Transmission Owner or other entity designated to construct, own and/or finance a recommended transmission enhancement or expansion from agreeing to undertake its responsibilities under such designation jointly with other Transmission Owners or other entities.

(m) Based on the planning analysis and other input from participants, including any indications of a willingness to bear cost responsibility for an enhancement or expansion, the recommended plan shall, for any enhancement or expansion that is included in the plan, designate (1) the Market Participant(s) in one or more Zones, or any other party that has agreed to fully fund upgrades pursuant to this Agreement or the PJM Tariff, that will bear cost responsibility for such enhancement or expansion, as and to the extent provided by any provision of the PJM Tariff or this Agreement, (2) in the event and to the extent that no provision of the PJM Tariff or this Agreement assigns cost responsibility, the Market Participant(s) in one or more Zones from which the cost of such enhancement or expansion shall be recovered through

charges established pursuant to the Tariff, Schedule 12, and (3) in the event and to the extent that the Coordinated System Plan developed under the Joint Operating Agreement Between the Midwest Independent System Operator, Inc. and PJM Interconnection, L.L.C. assigns cost responsibility, the Market Participant(s) in one or more Zones from which the cost of such enhancement or expansion shall be recovered. Any designation under clause (2) of the preceding sentence (A) shall further be based on the Office of the Interconnection's assessment of the contributions to the need for, and benefits expected to be derived from, the pertinent enhancement or expansion by affected Market Participants and, (B) subject to FERC review and approval, shall be incorporated in any amendment to the Tariff, Schedule 12 that establishes a Transmission Enhancement Charge Rate in connection with an economic expansion or enhancement developed under the Operating Agreement, Schedule 6, sections 1.5.6(i) and 1.5.7, (C) the costs associated with expansions and enhancements required to ensure the simultaneous feasibility of stage 1A Auction Revenue Rights allocated pursuant to the Operating Agreement, Schedule 1, section 7 shall (1) be allocated across transmission zones based on each zone's stage 1A eligible Auction Revenue Rights flow contribution to the total stage 1A eligible Auction Revenue Rights flow on the facility that limits stage 1A ARR feasibility and (2) within each transmission zone the Network Service Users and Transmission Customers that are eligible to receive stage 1A Auction Revenue Rights shall be the Responsible Customers under the Tariff, Schedule 12, section (b) for all expansions and enhancements included in the Regional Transmission Expansion Plan to ensure the simultaneous feasibility of stage 1A Auction Revenue Rights, and (D) the costs associated with expansions and enhancements required to reduce to zero the Locational Price Adder for LDAs as described in the Tariff, Attachment DD, section 15 shall (1) be allocated across Zones based on each Zone's pro rata share of load in such LDA and (2) within each Zone, to all LSEs serving load in such LDA pro rata based on such load.

Any designation under clause (3), above, (A) shall further be based on the Office of the Interconnection's assessment of the contributions to the need for, and benefits expected to be derived from, the pertinent enhancement or expansion by affected Market Participants, and (B), subject to FERC review and approval, shall be incorporated in an amendment to a Schedule of the PJM Tariff which establishes a charge in connection with the pertinent enhancement or expansion. Before designating fewer than all customers using Point-to-Point Transmission Service or Network Integration Transmission Service within a Zone as customers from which the costs of a particular enhancement or expansion may be recovered, Transmission Provider shall consult, in a manner and to the extent that it reasonably determines to be appropriate in each such instance, with affected state utility regulatory authorities and stakeholders. When the plan designates more than one responsible Market Participant, it shall also designate the proportional responsibility among them. Notwithstanding the foregoing, with respect to any facilities that the Regional Transmission Expansion Plan designates to be owned by an entity other than a Transmission Owner, the plan shall designate that entity as responsible for the costs of such facilities.

(n) Certain Regional RTEP Project(s) and Subregional RTEP Project(s) may not be required for compliance with the following PJM criteria: system reliability, market efficiency or operational performance, pursuant to a determination by the Office of the Interconnection.

These Supplemental Projects shall be separately identified in the RTEP and are not subject to approval by the PJM Board.

1.5.7 Development of Economic-based Enhancements or Expansions.

(a) Each year the Transmission Expansion Advisory Committee shall review and comment on the assumptions to be used in performing the market efficiency analysis to identify enhancements or expansions that could relieve transmission constraints that have an economic impact ("economic constraints"). Such assumptions shall include, but not be limited to, the discount rate used to determine the present value of the Total Annual Enhancement Benefit and Total Enhancement Cost, and the annual revenue requirement, including the recovery period, used to determine the Total Enhancement Cost. The discount rate shall be based on the Transmission Owners' most recent after-tax embedded cost of capital weighted by each Transmission Owner's total transmission capitalization. Each year, each Transmission Owner will be requested to provide the Office of the Interconnection with the Transmission Owner's most recent after-tax embedded cost of capital, total transmission capitalization, and levelized carrying charge rate, including the recovery period. The recovery period shall be consistent with recovery periods allowed by the Commission for comparable facilities. Prior to PJM Board consideration of such assumptions, the assumptions shall be presented to the Transmission Expansion Advisory Committee for review and comment. Following review and comment by the Transmission Expansion Advisory Committee, the Office of the Interconnection shall submit the assumptions to be used in performing the market efficiency analysis described in this Operating Agreement, Schedule 6, section 1.5.7 to the PJM Board for consideration.

(b) Following PJM Board consideration of the assumptions, the Office of the Interconnection shall perform a market efficiency analysis to compare the costs and benefits of: (i) accelerating reliability-based enhancements or expansions already included in the Regional Transmission Plan that if accelerated also could relieve one or more economic constraints; (ii) modifying reliability–based enhancements or expansions already included in the Regional Transmission Plan that as modified would relieve one or more economic constraints; and (iii) adding new enhancements or expansions that could relieve one or more economic constraints, but for which no reliability-based need has been identified. Economic constraints include, but are not limited to, constraints that cause: (1) significant historical gross congestion; (2) pro-ration of Stage 1B ARR requests as described in the Operating Agreement, Schedule 1, section 7.4.2(c); or (3) significant simulated congestion as forecasted in the market efficiency analysis. The timeline for the market efficiency analysis and comparison of the costs and benefits for items in the Operating Agreement, Schedule 6, section 1.5.7(b)(i-iii) is described in the PJM Manuals.

(c) The process for conducting the market efficiency analysis described in subsection (b) above shall include the following:

(i) The Office of the Interconnection shall identify and provide to the Transmission Expansion Advisory Committee a list of economic constraints to be evaluated in the market efficiency analysis.

(ii) The Office of the Interconnection shall identify any planned reliability-based enhancements or expansions already included in the Regional Transmission Expansion Plan,

which if accelerated would relieve such constraints, and present any such proposed reliability-based enhancements and expansions to be accelerated to the Transmission Expansion Advisory Committee for review and comment. The PJM Board, upon consideration of the advice of the Transmission Expansion Advisory Committee, thereafter shall consider and vote to approve any accelerations.

(iii) The Office of the Interconnection shall evaluate whether including any additional Economic-based Enhancements or Expansions in the Regional Transmission Expansion Plan or modifications of existing Regional Transmission Expansion Plan reliability-based enhancements or expansions would relieve an economic constraint. In addition, pursuant to the Operating Agreement, Schedule 6, section 1.5.8(c), any market participant may submit to the Office of the Interconnection a proposal to construct an additional Economic-based Enhancement or Expansion to relieve an economic constraint. Upon completion of its evaluation, including consideration of any eligible market participant proposed Economic-based Enhancements or Expansions, the Office of the Interconnection shall present to the Transmission Expansion Advisory Committee a description of new Economic-based Enhancements or Expansions for review and comment. Upon consideration and advice of the Transmission Expansion Advisory Committee, the PJM Board shall consider any new Economic-based Enhancements or Expansions for inclusion in the Regional Transmission Plan and for those enhancements and expansions it approves, the PJM Board shall designate (a) the entity or entities that will be responsible for constructing and owning or financing the additional Economic-based Enhancements or Expansions, (b) the estimated costs of such enhancements and expansions, and (c) the market participants that will bear responsibility for the costs of the additional Economic-based Enhancements or Expansions pursuant to the Operating Agreement, Schedule 6, section 1.5.6(m). In the event the entity or entities designated as responsible for construction, owning or financing a designated new Economic-based Enhancement or Expansion declines to construct, own or finance the new Economic-based Enhancement or Expansion, the enhancement or expansion will not be included in the Regional Transmission Expansion Plan but will be included in the report filed with the FERC in accordance with the Operating Agreement, Schedule 6, sections 1.6 and 1.7. This report also shall include information regarding PJM Board approved accelerations of reliability-based enhancements or expansions that an entity declines to accelerate.

(d) To determine the economic benefits of accelerating or modifying planned reliability-based enhancements or expansions or of constructing additional Economic-based Enhancements or Expansions and whether such Economic-based Enhancements or Expansion are eligible for inclusion in the Regional Transmission Expansion Plan, the Office of the Interconnection shall perform and compare market simulations with and without the proposed accelerated or modified planned reliability-based enhancements or expansions or the additional Economic-based Enhancements or Expansions as applicable, using the Benefit/Cost Ratio calculation set forth below in this Operating Agreement, Schedule 6, section 1.5.7(d). An Economic-based Enhancement or Expansion shall be included in the Regional Transmission Expansion Plan recommended to the PJM Board, if the relative benefits and costs of the Economic-based Enhancement or Expansion meet a Benefit/Cost Ratio Threshold of at least 1.25:1.

The Benefit/Cost Ratio shall be determined as follows:

Benefit/Cost Ratio = [Present value of the Total Annual Enhancement Benefit for the 15 year *period starting with the RTEP Year (defined as current year plus five) minus benefits for years when the project is not yet in-service*] ÷ [Present value of the Total Enhancement Cost for the *same* 15 year *period*]

Where

Total Annual Enhancement Benefit = Energy Market Benefit + Reliability Pricing Model Benefit

and

For economic-based enhancements and expansions for which cost responsibility is assigned pursuant to the Tariff, Schedule 12, section (b)(i) the Energy Market Benefit is as follows:

Energy Market Benefit = [.50] * [Change in Total Energy Production Cost] + [.50] * [Change in Load Energy Payment]

For economic-based enhancements and expansions for which cost responsibility is assigned pursuant to the Tariff, Schedule 12, section (b)(v) the Energy Market Benefit is as follows:

Energy Market Benefit = [1] * [Change in Load Energy Payment]
and

Change in Total Energy Production Cost = [the estimated total annual fuel costs, variable O&M costs, and emissions costs of the dispatched resources in the PJM Region without the Economic-based Enhancement or Expansion] – [the estimated total annual fuel costs, variable O&M costs, and emissions costs of the dispatched resources in the PJM Region with the Economic-based Enhancement or Expansion]. The change in costs for purchases from outside of the PJM Region and sales to outside the PJM Region will be captured, if appropriate. Purchases will be valued at the Load Weighted LMP and sales will be valued at the Generation Weighted LMP.

and

Change in Load Energy Payment = [the annual sum of (the hourly estimated zonal load megawatts for each Zone) * (the hourly

estimated zonal Locational Marginal Price for each Zone without the Economic-based Enhancement or Expansion)] – [the annual sum of (the hourly estimated zonal load megawatts for each Zone) * (the hourly estimated zonal Locational Marginal Price for each Zone with the Economic-based Enhancement or Expansion)] – [the change in value of transmission rights for each Zone with the Economic-based Enhancement or Expansion (as measured using currently allocated Auction Revenue Rights plus additional Auction Revenue Rights made available by the proposed acceleration or modification of the planned reliability-based enhancement or expansion or new Economic-based Enhancement or Expansion)]. The Change in the Load Energy Payment shall be the sum of the Change in the Load Energy Payment only of the Zones that show a decrease in the Load Energy Payment.

And

For economic-based enhancements and expansions for which cost responsibility is assigned pursuant to the Tariff, Schedule 12, section (b)(i) the Reliability Pricing Benefit is as follows:

Reliability Pricing Benefit = [.50] * [Change in Total System Capacity Cost] + [.50] * [Change in Load Capacity Payment]

and

For economic-based enhancements or expansions for which cost responsibility is assigned pursuant to the Tariff, Schedule 12, section (b)(v) the Reliability Pricing Benefit is as follows:

Reliability Pricing Benefit = [1] * [Change in Load Capacity Payment]

Change in Total System Capacity Cost = [the sum of (the megawatts that are estimated to be cleared in the Base Residual Auction under the Tariff, Attachment DD) * (the prices that are estimated to be contained in the Sell Offers for each such cleared megawatt without the Economic-based Enhancement or Expansion) * (the number of days in the study year)] – [the sum of (the megawatts that are estimated to be cleared in the Base Residual Auction under the Tariff, Attachment DD) * (the prices that are estimated to be contained in the Sell Offers for each such cleared megawatt with the Economic-based Enhancement or Expansion) * (the number of days in the study year)]

and

Change in Load Capacity Payment = [the sum of (the estimated zonal load megawatts in each Zone) * (the estimated Final Zonal Capacity Prices under the Tariff, Attachment DD without the Economic-based Enhancement or Expansion) * (the number of days in the study year)] – [the sum of (the estimated zonal load megawatts in each Zone) * (the estimated Final Zonal Capacity Prices under the Tariff, Attachment DD with the Economic-based Enhancement or Expansion) * (the number of days in the study year)]. The Change in Load Capacity Payment shall take account of the change in value of Capacity Transfer Rights in each Zone, including any additional Capacity Transfer Rights made available by the proposed acceleration or modification of the planned reliability-based enhancement or expansion or new Economic-based Enhancement or Expansion. The Change in the Load Capacity Payment shall be the sum of the change in the Load Capacity Payment only of the Zones that show a decrease in the Load Capacity Payment.

and

Total Enhancement Cost (except for accelerations of planned reliability-based enhancements or expansions) = the estimated annual revenue requirement for the Economic-based Enhancement or Expansion.

Total Enhancement Cost (for accelerations of planned reliability-based enhancements or expansions) = the estimated change in annual revenue requirement resulting from the acceleration of the planned reliability-based enhancement or expansion, taking account of all of the costs incurred that would not have been incurred but for the acceleration of the planned reliability-based enhancement or expansion.

(e) For informational purposes only, to assist the Office of the Interconnection and the Transmission Expansion Advisory Committee in evaluating the economic benefits of accelerating planned reliability-based enhancements or expansions or of constructing a new Economic-based Enhancement or Expansion, the Office of the Interconnection shall calculate and post on the PJM website the change in the following metrics on a zonal and system-wide basis: (i) total energy production costs (fuel costs, variable O&M costs and emissions costs);(ii) total load energy payments (zonal load MW times zonal load Locational Marginal Price); (iii) total generator revenue from energy production (generator MW times generator Locational Marginal Price); (iv) Financial Transmission Right credits (as measured using currently allocated Auction Revenue Rights plus additional Auction Revenue Rights made available by the proposed acceleration or modification of a planned reliability-based enhancement or expansion or new Economic-based Enhancement or Expansion); (v) marginal loss surplus credit; and (vi) total capacity costs and load capacity payments under the Office of the Interconnection's Commission-approved capacity construct.

(f) To assure that new Economic-based Enhancements or Expansions included in the Regional Transmission Expansion Plan continue to be cost beneficial, the Office of the Interconnection annually shall review the costs and benefits of constructing such enhancements and expansions. In the event that there are changes in these costs and benefits, the Office of the Interconnection shall review the changes in costs and benefits with the Transmission Expansion Advisory Committee and recommend to the PJM Board whether the new Economic-based Enhancements or Expansions continue to provide measurable benefits, as determined in accordance with subsection (d), and should remain in the Regional Transmission Expansion Plan. The annual review of the costs and benefits of constructing new Economic-based Enhancements or Expansions included in the Regional Transmission Expansion Plan shall include review of changes in cost estimates of the Economic-based Enhancement or Expansion, and changes in system conditions, including but not limited to, changes in load forecasts, and anticipated Merchant Transmission Facilities, generation, and demand response, consistent with the requirements of the Operating Agreement, Schedule 6, section 1.5.7(i). The Office of the Interconnection will not be required to review annually the costs and benefits of constructing Economic-based Enhancements or Expansions with capital costs less than $20 million if, based on updated cost estimates and the original benefits, the Benefit/Cost Ratio remains at or above 1.25. The Office of the Interconnection shall no longer be required to review costs and benefits of constructing Economic-based Enhancements and Expansions once: (i) a certificate of public convenience and necessity or its equivalent is granted by the state or relevant regulatory authority in which such enhancements or expansions will be located; or (ii) if a certificate of public convenience and necessity or its equivalent is not required by the state or relevant regulatory authority in which an economic-based enhancement or expansion will be located, once construction activities commence at the project site.

(g) For new economic enhancements or expansions with costs in excess of $50 million, an independent review of such costs shall be performed to assure both consistency of estimating practices and that the scope of the new Economic-based Enhancements or Expansions is consistent with the new Economic-based Enhancements or Expansions as recommended in the market efficiency analysis.

(h) At any time, market participants may submit to the Office of the Interconnection requests to interconnect Merchant Transmission Facilities or generation facilities pursuant to the Tariff, Parts IV and VI that could address an economic constraint. In the event the Office of the Interconnection determines that the interconnection of such facilities would relieve an economic constraint, the Office of the Interconnection may designate the project as a “market solution” and, in the event of such designation, the Tariff, Part VI, Subpart B, section 216, as applicable, shall apply to the project.

(i) The assumptions used in the market efficiency analysis described in subsection (b) and any review of costs and benefits pursuant to subsection (f) shall include, but not be limited to, the following:

(i) Timely installation of Qualifying Transmission Upgrades, that are committed to the PJM Region as a result of any Reliability Pricing

Model Auction pursuant to the Tariff, Attachment DD or any FRR Capacity Plan pursuant to the RAA, Schedule 8.1.

(ii) Availability of Generation Capacity Resources, as defined by the RAA, section 1.33, that are committed to the PJM Region as a result of any Reliability Pricing Model Auction pursuant to the Tariff, Attachment DD or any FRR Capacity Plan pursuant to the RAA, Schedule 8.1.

(iii) Availability of Demand Resources that are committed to the PJM Region as a result of any Reliability Pricing Model Auction pursuant to the Tariff, Attachment DD or any FRR Capacity Plan pursuant to the RAA, Schedule 8.1.

(iv) Addition of Customer Facilities or Generating Facilities, as applicable, pursuant to an executed Interconnection Service Agreement or executed Interim Interconnection Service Agreement for which Interconnection Service Agreement is expected to be executed, or Generating Facilities pursuant to an executed Generation Interconnection Agreement or executed Engineering and Procurement Agreement for which Generation Interconnection Agreement is expected to be executed. Facilities with an executed Facilities Study Agreement or suspended Interconnection Service Agreement, or that have an approved Decision Point II submission, under Tariff Part VII or VIII, as applicable, may be included by the Office of the Interconnection after review with the Transmission Expansion Advisory Committee.

(v) Addition of Customer-Funded Upgrades pursuant to an executed Interconnection Construction Service Agreement or an Upgrade Construction Service Agreement.

(vi) Expected level of demand response over at least the ensuing fifteen years based on analyses that consider historic levels of demand response, expected demand response growth trends, impact of capacity prices, current and emerging technologies.

(vii) Expected levels of potential new generation and generation retirements over at least the ensuing fifteen years based on analyses that consider generation trends based on existing generation on the system, generation in the PJM interconnection queues or Cycles as applicable and Capacity Resource Clearing Prices under the Tariff, Attachment DD. If the Office of the Interconnection finds that the PJM reserve requirement is not met in any of its future year market efficiency analyses then it will model Customer Facilities or Generating Facilities pursuant to an

executed Facilities Study Agreement approved Decision Point II submission under Tariff Part VII or VIII, or suspended Interconnection Service Agreement, ranked by their commercial probability. Commercial probability utilizes historical data from the PJM interconnection queues or Cycles as applicable to determine the likelihood of a Customer Facility or Generating Facility, pursuant to an executed Facilities Study Agreement approved Decision Point II submission under Tariff Part VII or VIII, or suspended Interconnection Service Agreement, reaching commercial operation. If the Office of the Interconnection finds that the PJM reserve requirement is not met in any of its future year market efficiency analyses, following inclusion of the Customer Facilities or Generating Facilities discussed above in this section 1.5.7(i)(vii), then it will model adequate future generation based on type and location of generation in existing PJM interconnection queues or Cycles as applicable and, if necessary, add transmission enhancements to address congestion that arises from such modeling.

(viii) Items (i) through (v) will be included in the market efficiency assumptions if qualified for consideration by the PJM Board. In the event that any of the items listed in (i) through (v) above qualify for inclusion in the market efficiency analysis assumptions, however, because of the timing of the qualification the item was not included in the assumptions used in developing the most recent Regional Transmission Expansion Plan, the Office of the Interconnection, to the extent necessary, shall notify any entity constructing an Economic-based Enhancement or Expansion that may be affected by inclusion of such item in the assumptions for the next market efficiency analysis described in subsection (b) and any review of costs and benefits pursuant to subsection (f) that the need for the Economic-based Enhancement or Expansion may be diminished or obviated as a result of the inclusion of the qualified item in the assumptions for the next annual market efficiency analysis or review of costs and benefits.

(j) For informational purposes only, with regard to Economic-based Enhancements or Expansions that are included in the Regional Transmission Expansion Plan pursuant to subsection (d) of this section 1.5.7, the Office of the Interconnection shall perform sensitivity analyses consistent with the Operating Agreement, Schedule 6, section 1.5.3 and shall provide the results of such sensitivity analyses to the Transmission Expansion Advisory Committee.

1.5.8 Development of Long-lead Projects, Short-term Projects, Immediate-need Reliability Projects, and Economic-based Enhancements or Expansions.

(a) **Pre-Qualification Process**.

(a)(1) On September 1 of each year, the Office of the Interconnection shall open a thirty-day pre-qualification window for entities, including existing Transmission Owners and Nonincumbent Developers, to submit to the Office of the Interconnection: (i) applications to pre-qualify as eligible to be a Designated Entity; or (ii) updated information as described in the Operating Agreement, Schedule 6, section 1.5.8(a)(3). Pre-qualification applications shall contain the following information: (i) name and address of the entity; (ii) the technical and engineering qualifications of the entity or its affiliate, partner, or parent company; (iii) the demonstrated experience of the entity or its affiliate, partner, or parent company to develop, construct, maintain, and operate transmission facilities, including a list or other evidence of transmission facilities the entity, its affiliate, partner, or parent company previously developed, constructed, maintained, or operated; (iv) the previous record of the entity or its affiliate, partner, or parent company regarding construction, maintenance, or operation of transmission facilities both inside and outside of the PJM Region; (v) the capability of the entity or its affiliate, partner, or parent company to adhere to standardized construction, maintenance and operating practices; (vi) the financial statements of the entity or its affiliate, partner, or parent company for the most recent fiscal quarter, as well as the most recent three fiscal years, or the period of existence of the entity, if shorter, or such other evidence demonstrating an entity's or its affiliate's, partner's, or parent company's current and expected financial capability acceptable to the Office of the Interconnection; (vii) a commitment by the entity to execute the Consolidated Transmission Owners Agreement, if the entity becomes a Designated Entity; (viii) evidence demonstrating the ability of the entity or its affiliate, partner, or parent company to address and timely remedy failure of facilities; (ix) a description of the experience of the entity or its affiliate, partner, or parent company in acquiring rights of way; and (x) such other supporting information that the Office of Interconnection requires to make the pre-qualification determinations consistent with this Operating Agreement, Schedule 6, section 1.5.8(a).

(a)(2) No later than October 31, the Office of the Interconnection shall notify the entities that submitted pre-qualification applications or updated information during the annual thirty-day pre-qualification window, whether they are, or will continue to be, pre-qualified as eligible to be a Designated Entity. In the event the Office of the Interconnection determines that an entity (i) is not, or no longer will continue to be, pre-qualified as eligible to be a Designated Entity, or (ii) provided insufficient information to determine pre-qualification, the Office of the Interconnection shall inform that the entity it is not pre-qualified and include in the notification the basis for its determination. The entity then may submit additional information, which the Office of the Interconnection shall consider in re-evaluating whether the entity is, or will continue to be, pre-qualified as eligible to be a Designated Entity. If the entity submits additional information by November 30, the Office of the Interconnection shall notify the entity of the results of its re-evaluation no later than December 15. If the entity submits additional information after November 30, the Office of the Interconnection shall use reasonable efforts to re-evaluate the application, with the additional information, and notify the entity of its determination as soon as practicable. No later than December 31, the Office of the Interconnection shall post on the PJM website the list of entities that are pre-qualified as eligible to be Designated Entities. If an entity is notified by the Office of the Interconnection that it does not pre-qualify or will not continue to be pre-qualified as eligible to be a Designated Entity, such entity may request dispute resolution pursuant to the Operating Agreement, Schedule 5.

(a)(3) In order to continue to pre-qualify as eligible to be a Designated Entity, such entity must confirm its information with the Office of the Interconnection no later than three years following its last submission or sooner if necessary as required below. In the event the information on which the entity's pre-qualification is based changes with respect to the upcoming year, such entity must submit to the Office of the Interconnection all updated information during the annual thirty-day pre-qualification window and the timeframes for notification in the Operating Agreement, Schedule 6, section 1.5.8(a)(2) shall apply. In the event the information on which the entity's pre-qualification is based changes with respect to the current year, such entity must submit to the Office of the Interconnection all updated information at the time the information changes and the Office of the Interconnection shall use reasonable efforts to evaluate the updated information and notify the entity of its determination as soon as practicable.

(a)(4) As determined by the Office of the Interconnection, an entity may submit a pre-qualification application outside the annual thirty-day pre-qualification window for good cause shown. For a pre-qualification application received outside of the annual thirty-day pre-qualification window, the Office of the Interconnection shall use reasonable efforts to process the application and notify the entity as to whether it pre-qualifies as eligible to be a Designated Entity as soon as practicable.

(a)(5) To be designated as a Designated Entity for any project proposed pursuant to the Operating Agreement, Schedule 6, section 1.5.8, existing Transmission Owners and Nonincumbent Developers must be pre-qualified as eligible to be a Designated Entity pursuant to this Operating Agreement, Schedule 6, section 1.5.8(a). This Operating Agreement, Schedule 6, section 1.5.8(a) shall not apply to entities that desire to propose projects for inclusion in the recommended plan but do not intend to be a Designated Entity.

(b) **Posting of Transmission System Needs**. Following identification of existing and projected limitations on the Transmission System's physical, economic and/or operational capability or performance in the enhancement and expansion analysis process described in this Operating Agreement, Schedule 6 and the PJM Manuals, and after consideration of non-transmission solutions, and prior to evaluating potential enhancements and expansions to the Transmission System, the Office of the Interconnection shall publicly post on the PJM website all transmission need information, including violations, system conditions, and economic constraints, and Public Policy Requirements, including (i) federal Public Policy Requirements; (ii) state Public Policy Requirements identified or agreed-to by the states in the PJM Region, which could be addressed by potential Short-term Projects, Long-lead Projects or projects determined pursuant to the State Agreement Approach in the Operating Agreement, Schedule 6, section 1.5.9, as applicable. Such posting shall support the role of the Subregional RTEP Committees in the development of the Local Plans and support the role of the Transmission Expansion Advisory Committee in the development of the Regional Transmission Expansion Plan. The Office of the Interconnection also shall post an explanation regarding why transmission needs associated with federal or state Public Policy Requirements were identified but were not selected for further evaluation.

(c) **Project Proposal Windows**. The Office of the Interconnection shall provide notice to stakeholders of a 60-day proposal window for Short-term Projects and a 120-day proposal window for Long-lead Projects and Economic-based Enhancements or Expansions. The specifics regarding whether or not the following types of violations or projects are subject to a proposal window are detailed in the Operating Agreement, Schedule 6, section 1.5.8(m) for Immediate-need Reliability Projects; Operating Agreement, Schedule 6, section 1.5.8(n) for reliability violations on transmission facilities below 200 kV; and Operating Agreement, Schedule 6, section 1.5.8(p) for violations on transmission substation equipment. The Office of Interconnection may shorten a proposal window should an identified need require a shorter proposal window to meet the needed in-service date of the proposed enhancements or expansions, or extend a proposal window as needed to accommodate updated information regarding system conditions. The Office of the Interconnection may shorten or lengthen a proposal window that is not yet opened based on one or more of the following criteria: (1) complexity of the violation or system condition; and (2) whether there is sufficient time remaining in the relevant planning cycle to accommodate a standard proposal window and timely address the violation or system condition. The Office of the Interconnection may lengthen a proposal window that already is opened based on or more of the following criteria: (i) changes in assumptions or conditions relating to the underlying need for the project, such as load growth or Reliability Pricing Model auction results; (ii) availability of new or changed information regarding the nature of the violations and the facilities involved; and (iii) time remaining in the relevant proposal window. In the event that the Office of the Interconnection determines to lengthen or shorten a proposal window, it will post on the PJM website the new proposal window period and an explanation as to the reasons for the change in the proposal window period. During these windows, the Office of the Interconnection will accept proposals from existing Transmission Owners and Nonincumbent Developers for potential enhancements or expansions to address the posted violations, system conditions, economic constraints, as well as Public Policy Requirements.

(c)(1) All proposals submitted in the proposal windows must contain: (i) the name and address of the proposing entity; (ii) a statement whether the entity intends to be the Designated Entity for the proposed project; (iii) the location of proposed project, including source and sink, if applicable; (iv) relevant engineering studies, and other relevant information as described in the PJM Manuals pertaining to the proposed project; (v) a proposed initial construction schedule including projected dates on which needed permits are required to be obtained in order to meet the required in-service date; (vi) cost estimates and analyses that provide sufficient detail for the Office of Interconnection to review and analyze the proposed cost of the project; and (vii) with the exception of project proposals submitted with cost estimates of $5 million or less, a $5,000 non-refundable deposit must be included with each project proposal submitted by a proposing entity that indicates an intention to be the Designated Entity.

(c)(1)(i) In addition, any proposing entity indicating its intention to be the Designated Entity will be responsible for and must pay all actual costs incurred by the Transmission Provider to evaluate the submitted project proposal. To the extent the Transmission Provider incurs costs to evaluate multiple submitted project proposals where such costs are not severable by individual project proposal, the Transmission Provider shall invoice equal shares of the non-severable costs among the project proposals that cause such non-

severable costs to be incurred. Notwithstanding this method of invoicing non-severable costs, non-severable costs will be jointly and severally owed by the proposing entities that cause such costs to be incurred.

(c)(1)(ii) All non-refundable deposits will be credited towards the actual costs incurred by the Transmission Provider as a result of the evaluation of a submitted project proposal.

(c)(1)(iii) Following the close of a proposal window but before the Transmission Provider incurs any third-party consultant work costs to evaluate a submitted project proposal, the Transmission Provider will issue to the proposing entity an initial invoice seeking payment of estimated costs to evaluate each submitted project proposal. The estimated costs will be determined by considering the: potential cost of consultant work, historical estimates for project proposals of similar scope, complexity and nature of the need, and/or technology and nature of the project proposal. The Transmission Provider may issue additional invoices to the proposing entity prior to the completion of the evaluation activities associated with a project proposal if the Transmission Provider receives updated actual cost information and/or upon consideration of the factors specified in this section.

(c)(1)(iv) At the completion of the evaluation activities associated with a project proposal, the Transmission Provider will reconcile the actual costs with monies paid and, to the extent necessary, issue either a final invoice or refund.

(c)(1)(v) The proposing party must pay any invoiced costs within fifteen (15) calendar days of the Transmission Provider sending the invoice to the proposing entity or its agent. For good cause shown, this fifteen (15) calendar day time period may be extended by the Transmission Provider. If the proposing entity fails to pay any invoice within the time period specified and/or extended by the Transmission Provider in accordance with this section, the proposing entity's pre-qualification status may be suspended and the proposing entity will be ineligible to be a Designated Entity for any projects that do not yet have an executed Designated Entity Agreement. Such a suspension and/or ineligibility will remain in place until the proposing entity pays in full all outstanding monies owed to the Transmission Provider as a result of the evaluation of the proposing entity's project proposal(s).

(c)(2) Proposals from all entities (both existing Transmission Owners and Nonincumbent Developers) that indicate the entity intends to be a Designated Entity, also must contain information to the extent not previously provided pursuant to the Operating Agreement, Schedule 6, section 1.5.8(a) demonstrating: (i) technical and engineering qualifications of the entity, its affiliate, partner, or parent company relevant to construction, operation, and maintenance of the proposed project; (ii) experience of the entity, its affiliate, partner, or parent company in developing, constructing, maintaining, and operating the type of transmission facilities contained in the project proposal; (iii) the emergency response capability of the entity that will be operating and maintaining the proposed project; (iv) evidence of transmission facilities the entity, its affiliate, partner, or parent company previously constructed, maintained, or operated; (v) the ability of the entity or its affiliate, partner, or parent company to obtain adequate financing relative to the proposed project, which may include a letter of intent from a

financial institution approved by the Office of the Interconnection or such other evidence of the financial resources available to finance the construction, operation, and maintenance of the proposed project; (vi) the managerial ability of the entity, its affiliate, partner, or parent company to contain costs and adhere to construction schedules for the proposed project, including a description of verifiable past achievement of these goals; (vii) a demonstration of other advantages the entity may have to construct, operate, and maintain the proposed project, including any binding cost commitment proposal the entity may wish to submit; and (viii) any other information that may assist the Office of the Interconnection in evaluating the proposed project. To the extent that an entity submits a cost containment proposal the entity shall submit sufficient information for the Office of Interconnection to determine the binding nature of the proposal with respect to critical elements of project development. PJM may not alter the requirements for proposal submission to require the submission of a binding cost containment proposal, in whole or in part, or otherwsise mandate or unilaterally alter the terms of any such proposal or the requirements for proposal submission, the submission of any such proposals at all times remaining voluntary.

(c)(3) The Office of the Interconnection may request additional reports or information from an existing Transmission Owner or Nonincumbent Developers that it determines are reasonably necessary to evaluate its specific project proposal pursuant to the criteria set forth in the Operating Agreement, Schedule 6, sections 1.5.8(e) and 1.5.8(f). If the Office of the Interconnection determines any of the information provided in a proposal is deficient or it requires additional reports or information to analyze the submitted proposal, the Office of the Interconnection shall notify the proposing entity of such deficiency or request. Within 10 Business Days of receipt of the notification of deficiency and/or request for additional reports or information, or other reasonable time period as determined by the Office of the Interconnection, the proposing entity shall provide the necessary information.

(c)(4) The request for additional reports or information by the Office of the Interconnection pursuant to the Operating Agreement, Schedule 6, section 1.5.8(c)(3) may be used only to clarify a proposed project as submitted. In response to the Office of the Information's request for additional reports or information, the proposing entity (whether an existing Transmission Owner or Nonincumbent Developer) may not submit a new project proposal or modifications to a proposed project once the proposal window is closed. In the event that the proposing entity fails to timely cure the deficiency or provide the requested reports or information regarding a proposed project, the proposed project will not be considered for inclusion in the recommended plan.

(c)(5) Within 30 days of the closing of the proposal window, the Office of the Interconnection may notify the proposing entity that additional per project fees are required if the Office of the Interconnection determines the proposing entity's submittal includes multiple project proposals. Within 10 Business Days of receipt of the notification of insufficient funds by the Office of the Interconnection, the proposing entity shall submit such funds or notify the Office of the Interconnection which of the project proposals the Office of the Interconnection should evaluate based on the fee(s) submitted.

(d) **Posting and Review of Projects**. Following the close of a proposal window, the Office of the Interconnection shall post on the PJM website all proposals submitted pursuant to the Operating Agreement, Schedule 6, section 1.5.8(c). All proposals addressing state Public Policy Requirements shall be provided to the applicable states in the PJM Region for review and consideration as a Supplemental Project or a state public policy project consistent with the Operating Agreement, Schedule 6, section 1.5.9. The Office of the Interconnection shall review all proposals submitted during a proposal window and determine and present to the Transmission Expansion Advisory Committee the proposals that merit further consideration for inclusion in the recommended plan. In making this determination, the Office of the Interconnection shall consider the criteria set forth in the Operating Agreement, Schedule 6, sections 1.5.8(e) and 1.5.8(f). The Office of the Interconnection shall post on the PJM website and present to the Transmission Expansion Advisory Committee for review and comment descriptions of the proposed enhancements and expansions, including any proposed Supplemental Projects or state public policy projects identified by a state(s). Based on review and comment by the Transmission Expansion Advisory Committee, the Office of the Interconnection may, if necessary conduct further study and evaluation. The Office of the Interconnection shall post on the PJM website and present to the Transmission Expansion Advisory Committee the revised enhancements and expansions for review and comment. After consultation with the Transmission Expansion Advisory Committee, the Office of the Interconnection shall determine the more efficient or cost-effective transmission enhancements and expansions for inclusion in the recommended plan consistent with this Operating Agreement, Schedule 6.

(e) **Criteria for Considering Inclusion of a Project in the Recommended Plan**. In determining whether a Short-term Project or Long-lead Project proposed pursuant to the Operating Agreement, Schedule 6, section 1.5.8(c), individually or in combination with other Short-term Projects or Long-lead Projects, is the more efficient or cost-effective solution and therefore should be included in the recommended plan, the Office of the Interconnection, taking into account sensitivity studies and scenario analyses considered pursuant to the Operating Agreement, Schedule 6, section 1.5.3, shall consider the following criteria, to the extent applicable: (i) the extent to which a Short-term Project or Long-lead Project would address and solve the posted violation, system condition, or economic constraint; (ii) the extent to which the relative benefits of the project meets a Benefit/Cost Ratio Threshold of at least 1.25:1 as calculated pursuant to the Operating Agreement, Schedule 6, section 1.5.7(d); (iii) the extent to which the Short-term Project or Long-lead Project would have secondary benefits, such as addressing additional or other system reliability, operational performance, economic efficiency issues or federal Public Policy Requirements or state Public Policy Requirements identified by the states in the PJM Region; and (iv) the ability to timely complete the project, and project development feasibility; and (v) other factors such as cost-effectiveness, including the quality and effectiveness of any voluntary-submitted binding cost commitment proposal related to Transmission Facilities which caps project construction costs (either in whole or in part), project total return on equity (including incentive adders), or capital structure. In scrutinizing the cost of project proposals, the Office of Interconnection shall determine for each project finalist's proposal, including any Transmission Owner Upgrades, the comparative risks to be borne by ratepayers as a result of the proposal's binding cost commitment or the use of non-binding cost estimates. Such comparative analysis shall detail, in a clear and transparent manner, the method by which the Office of Interconnection scrutinized the cost and overall cost-effectiveness of each

finalist's proposal, including any binding cost commitments. Such comparative analysis shall be presented to the TEAC for review and comment. In evaluating any cost, ROE and/or capital structure proposal, PJM is not making a determination that the cost, ROE or capital structure results in just and reasonable rates, which shall be addressed in the required rate filing with the FERC. Stakeholders seeking to dispute a particular ROE analysis utilized in the selection process may address such disputes with the Designated Entity in the applicable rate proceeding where the Designated Entity seeks approval of such rates from the Commission. PJM may modify the technical specifications of a proposal, as outlined in the PJM Manuals, which may result in the modified proposal being determined to be the more efficient or cost-effective proposal for recommendation to the PJM Board. Neither PJM, the Designated Entity nor any stakeholders are waiving any of their respective FPA section 205 or 206 rights through this process. Challenges to the Designated Entity Agreements are subject to the just and reasonable standard.

(f) **Entity-Specific Criteria Considered in Determining the Designated Entity for a Project**. In determining whether the entity proposing a Short-term Project, Long-lead Project or Economic-based Enhancement or Expansion recommended for inclusion in the plan shall be the Designated Entity, the Office of the Interconnection shall consider: (i) whether in its proposal, the entity indicated its intent to be the Designated Entity; (ii) whether the entity is pre-qualified to be a Designated Entity pursuant to Operating Agreement, Schedule 6, section 1.5.8(a); (iii) information provided either in the proposing entity's submission pursuant to the Operating Agreement, Schedule 6, section 1.5.8(a) or 1.5.8(c)(2) relative to the specific proposed project that demonstrates: (1) the technical and engineering experience of the entity or its affiliate, partner, or parent company, including its previous record regarding construction, maintenance, and operation of transmission facilities relative to the project proposed; (2) ability of the entity or its affiliate, partner, or parent company to construct, maintain, and operate transmission facilities, as proposed, (3) capability of the entity to adhere to standardized construction, maintenance, and operating practices, including the capability for emergency response and restoration of damaged equipment; (4) experience of the entity in acquiring rights of way; (5) evidence of the ability of the entity, its affiliate, partner, or parent company to secure a financial commitment from an approved financial institution(s) agreeing to finance the construction, operation, and maintenance of the project, if it is accepted into the recommended plan; and (iv) any other factors that may be relevant to the proposed project, including but not limited to whether the proposal includes the entity's previously designated project(s) included in the plan.

(g) **Procedures if No Long-lead Project or Economic-based Enhancement or Expansion Proposal is Determined to be the More Efficient or Cost-Effective Solution**. If the Office of the Interconnection determines that none of the proposed Long-lead Projects received during the Long-lead Project proposal window would be the more efficient or cost-effective solution to resolve a posted violation, or system condition, the Office of the Interconnection may re-evaluate and re-post on the PJM website the unresolved violations, or system conditions pursuant to the Operating Agreement, Schedule 6, section 1.5.8(b), provided such re-evaluation and re-posting would not affect the ability of the Office of the Interconnection to timely address the identified reliability need. In the event that re-posting and conducting such re-evaluation would prevent the Office of the Interconnection from timely addressing the existing and projected limitations on the Transmission System that give rise to the need for an enhancement or expansion, the Office

of the Interconnection shall propose a project to solve the posted violation, or system condition for inclusion in the recommended plan and shall present such project to the Transmission Expansion Advisory Committee for review and comment. The Transmission Owner(s) in the Zone(s) where the project is to be located shall be the Designated Entity(ies) for such project. In determining whether there is insufficient time for re-posting and re-evaluation, the Office of the Interconnection shall develop and post on the PJM website a transmission solution construction timeline for input and review by the Transmission Expansion Advisory Committee that will include factors such as, but not limited to: (i) deadlines for obtaining regulatory approvals, (ii) dates by which long lead equipment should be acquired, (iii) the time necessary to complete a proposed solution to meet the required in-service date, and (iv) other time-based factors impacting the feasibility of achieving the required in-service date. Based on input from the Transmission Expansion Advisory Committee and the time frames set forth in the construction timeline, the Office of the Interconnection shall determine whether there is sufficient time to conduct a re-evaluation and re-post and timely address the existing and projected limitations on the Transmission System that give rise to the need for an enhancement or expansion. To the extent that an economic constraint remains unaddressed, the economic constraint will be re-evaluated and re-posted.

(h) **Procedures if No Short-term Project Proposal is Determined to be the More Efficient or Cost-Effective Solution**. If the Office of the Interconnection determines that none of the proposed Short-term Projects received during a Short-term Project proposal window would be the more efficient or cost-effective solution to resolve a posted violation or system condition, the Office of the Interconnection shall propose a Short-term Project to solve the posted violation, or system condition for inclusion in the recommended plan and will present such Short-term Project to the Transmission Expansion Advisory Committee for review and comment. The Transmission Owner(s) in the Zone(s) where the Short-term Project is to be located shall be the Designated Entity(ies) for the Project.

(i) **Notification of Designated Entity**. Within 15 Business Days of PJM Board approval of the Regional Transmission Expansion Plan, the Office of the Interconnection shall notify the entities that have been designated as the Designated Entities for projects included in the Regional Transmission Expansion Plan of such designations. In such notices, the Office of the Interconnection shall provide: (i) the needed in-service date of the project; and (ii) a date by which all necessary state approvals should be obtained to timely meet the needed in-service date of the project. The Office of the Interconnection shall use these dates as part of its on-going monitoring of the progress of the project to ensure that the project is completed by its needed in-service date.

(j) **Acceptance of Designation**. Within 30 days of receiving notification of its designation as a Designated Entity, the existing Transmission Owner or Nonincumbent Developer shall notify the Office of the Interconnection of its acceptance of such designation and submit to the Office of the Interconnection a development schedule, which shall include, but not be limited to, milestones necessary to develop and construct the project to achieve the required in-service date, including milestone dates for obtaining all necessary authorizations and approvals, including but not limited to, state approvals. For good cause shown, the Office of the Interconnection may extend the deadline for submitting the development schedule. The Office of the Interconnection then shall review the development schedule and within 15 days or other reasonable time as

required by the Office of the Interconnection: (i) notify the Designated Entity of any issues regarding the development schedule identified by the Office of the Interconnection that may need to be addressed to ensure that the project meets its needed in-service date; and (ii) tender to the Designated Entity an executable Designated Entity Agreement setting forth the rights and obligations of the parties. To retain its status as a Designated Entity, within 60 days of receiving an executable Designated Entity Agreement (or other such period as mutually agreed upon by the Office of the Interconnection and the Designated Entity), the Designated Entity (both existing Transmission Owners and Nonincumbent Developers) shall submit to the Office of the Interconnection a letter of credit as determined by the Office of Interconnection to cover the incremental costs of construction resulting from reassignment of the project, and return to the Office of the Interconnection an executed Designated Entity Agreement containing a mutually agreed upon development schedule. In the alternative, the Designated Entity may request dispute resolution pursuant to the Operating Agreement, Schedule 5, or request that the Designated Entity Agreement be filed unexecuted with the Commission.

(k) **Failure of Designated Entity to Meet Milestones**. In the event the Designated Entity fails to comply with one or more of the requirements of the Operating Agreement, Schedule 6, section 1.5.8(j); or fails to meet a milestone in the development schedule set forth in the Designated Entity Agreement that causes a delay of the project's in-service date, the Office of the Interconnection shall re-evaluate the need for the Short-term Project or Long-lead Project, and based on that re-evaluation may: (i) retain the Short-term Project or Long-lead Project in the Regional Transmission Expansion Plan; (ii) remove the Short-term Project or Long-lead Project from the Regional Transmission Expansion Plan; or (iii) include an alternative solution in the Regional Transmission Expansion Plan. If the Office of the Interconnection retains the Short-term or Long-term Project in the Regional Transmission Expansion Plan, it shall determine whether the delay is beyond the Designated Entity's control and whether to retain the Designated Entity or to designate the Transmission Owner(s) in the Zone(s) where the project is located as Designated Entity(ies) for the Short-term Project or Long-lead Project. If the Designated Entity is the Transmission Owner(s) in the Zone(s) where the project is located, the Office of the Interconnection shall seek recourse through the Consolidated Transmission Owners Agreement or FERC, as appropriate. Any modifications to the Regional Transmission Expansion Plan pursuant to this section shall be presented to the Transmission Expansion Advisory Committee for review and comment and approved by the PJM Board.

(l) **Transmission Owners Required to be the Designated Entity**. Notwithstanding anything to the contrary in this Operating Agreement, Schedule 6, section 1.5.8, in all events, the Transmission Owner(s) in whose Zone(s) a project proposed pursuant to the Operating Agreement, Schedule 6, section 1.5.8(c) is to be located will be the Designated Entity for the project, when the Short-term Project or Long-lead Project is: (i) a Transmission Owner Upgrade; (ii) located solely within a Transmission Owner's Zone and the costs of the project are allocated solely to the Transmission Owner's Zone; (iii) located solely within a Transmission Owner's Zone and is not selected in the Regional Transmission Expansion Plan for purposes of cost allocation; or (iv) proposed to be located on a Transmission Owner's existing right of way and the project would alter the Transmission Owner's use and control of its existing right of way under state law. Transmission Owner shall be the Designated Entity when required by state law,

regulation or administrative agency order with regard to enhancements or expansions or portions of such enhancements or expansions located within that state.

(m) **Immediate-need Reliability Projects**:

(m)(1) Pursuant to the expansion planning process set forth in Operating Agreement, Schedule 6, sections 1.5.1 through 1.5.6, the Office of the Interconnection shall identify immediate reliability needs that must be addressed within three years or less. For those immediate reliability needs for which PJM determines a proposal window may not be feasible, PJM shall identify and post such immediate need reliability criteria violations and system conditions for review and comment by the Transmission Expansion Advisory Committee and other stakeholders. Following review and comment, the Office of the Interconnection shall develop Immediate-need Reliability Projects for which a proposal window pursuant to the Operating Agreement, Schedule 6, section 1.5.8(m)(2) is infeasible. The Office of the Interconnection shall consider the following factors in determining the infeasibility of such a proposal window: (i) nature of the reliability criteria violation; (ii) nature and type of potential solution required; and (iii) projected construction time for a potential solution to the type of reliability criteria violation to be addressed. The Office of the Interconnection shall post on the PJM website for review and comment by the Transmission Expansion Advisory Committee and other stakeholders descriptions of the Immediate-need Reliability Projects for which a proposal window pursuant to the Operating Agreement, Schedule 6, section 1.5.8(m)(2) is infeasible. Stakeholders shall be afforded no less than ten days to review Immediate-need Reliability Project materials prior to providing comments at stakeholder meetings. However, PJM may review Immediate-need Reliability Project materials with stakeholders without the requisite ten-day notice so long as: (i) stakeholders do not object to reviewing the materials or (ii) PJM identifies in its posting to the meeting materials extenuating circumstances identified by PJM that require review of the materials at the stakeholder meeting. The descriptions shall include an explanation of the decision to designate the Transmission Owner as the Designated Entity for the Immediate-need Reliability Project rather than conducting a proposal window pursuant to the Operating Agreement, Schedule 6, section 1.5.8(m)(2), including an explanation of the time-sensitive need for the Immediate-need Reliability Project, other transmission and non-transmission options that were considered but concluded would not sufficiently address the immediate reliability need, the circumstances that generated the immediate reliability need, and why the immediate reliability need was not identified earlier. After the descriptions are posted on the PJM website, stakeholders shall have reasonable opportunity to provide comments to the Office of the Interconnection. All comments received by the Office of the Interconnection shall be publicly available on the PJM website. Based on the comments received from stakeholders and the review by Transmission Expansion Advisory Committee, the Office of the Interconnection shall, if necessary, conduct further study and evaluation and post a revised recommended plan for review and comment by the Transmission Expansion Advisory Committee. The PJM Board shall approve the Immediate-need Reliability Projects for inclusion in the recommended plan. In January of each year, the Office of the Interconnection shall post on the PJM website and file with the Commission for informational purposes a list of the Immediate-need Reliability Projects for which an existing Transmission Owner was designated in the prior year as the Designated Entity in accordance with this Operating Agreement, Schedule 6, section 1.5.8(m)(1). The list

shall include the need-by date of Immediate-need Reliability Project and the date the Transmission Owner actually energized the Immediate-need Reliability Project.

(m)(2) If, in the judgment of the Office of the Interconnection, there is sufficient time for the Office of the Interconnection to accept proposals in a shortened proposal window for Immediate-need Reliability Projects, the Office of the Interconnection shall post on the PJM website the violations and system conditions that could be addressed by Immediate-need Reliability Project proposals, including an explanation of the time-sensitive need for an Immediate-need Reliability Project and provide notice to stakeholders of a shortened proposal window. Proposals must contain the information required in the Operating Agreement, Schedule 6, section 1.5.8(c) and, if the entity is seeking to be the Designated Entity, such entity must have pre-qualified to be a Designated Entity pursuant to the Operating Agreement, Schedule 6, section 1.5.8(a). In determining the more efficient or cost-effective proposed Immediate-need Reliability Project for inclusion in the recommended plan, the Office of the Interconnection shall consider the extent to which the proposed Immediate-need Reliability Project, individually or in combination with other Immediate-need Reliability Projects, would address and solve the posted violations or system conditions and other factors such as cost-effectiveness, the ability of the entity to timely complete the project, and project development feasibility in light of the required need. After PJM Board approval, the Office of the Interconnection, in accordance with the Operating Agreement, Schedule 6, section 1.5.8(i), shall notify the entities that have been designated as Designated Entities for Immediate-need Projects included in the Regional Transmission Expansion Plan of such designations. Designated Entities shall accept such designations in accordance with the Operating Agreement, Schedule 6, section 1.5.8(j). In the event that (i) the Office of the Interconnection determines that no proposal resolves a posted violation or system condition; (ii) the proposing entity is not selected to be the Designated Entity; (iii) an entity does not accept the designation as a Designated Entity; or (iv) the Designated Entity fails to meet milestones that would delay the in-service date of the Immediate-need Reliability Project, the Office of the Interconnection shall develop and recommend an Immediate-need Reliability Project to solve the violation or system needs in accordance with the Operating Agreement, Schedule 6, section 1.5.8(m)(1).

(n) **Reliability Violations on Transmission Facilities Below 200 kV.** Pursuant to the expansion planning process set forth in the Operating Agreement, Schedule 6, sections 1.5.1 through 1.5.6, the Office of the Interconnection shall identify reliability violations on facilities below 200 kV. The Office of the Interconnection shall not post such a violation pursuant to the Operating Agreement, Schedule 6, section 1.5.8(b) for inclusion in a proposal window pursuant to the Operating Agreement, Schedule 6, section 1.5.8(c) unless the identified violation(s) satisfies one of the following exceptions: (i) the reliability violations are thermal overload violations identified on multiple transmission lines and/or transformers rated below 200 kV that are impacted by a common contingent element, such that multiple reliability violations could be addressed by one or more solutions, including but not limited to a higher voltage solution; or (ii) the reliability violations are thermal overload violations identified on multiple transmission lines and/or transformers rated below 200 kV and the Office of the Interconnection determines that given the location and electrical features of the violations one or more solutions could potentially address or reduce the flow on multiple lower voltage facilities, thereby eliminating the multiple reliability violations. If the reliability violation is identified on multiple facilities rated below

200 kV that are determined by the Office of the Interconnection to meet one of the two exceptions stated above, the Office of the Interconnection shall post on the PJM website the reliability violations to be included in a proposal window consistent with the Operating Agreement, Schedule 6, section 1.5.8(c). If the Office of the Interconnection determines that the identified reliability violations do not satisfy either of the two exceptions stated above, the Office of the Interconnection shall develop a solution to address the reliability violation on below 200 kV Transmission Facilities that will not be included in a proposal window pursuant to the Operating Agreement, Schedule 6, section 1.5.8(c). The Office of Interconnection shall post on the PJM website for review and comment by the Transmission Expansion Advisory Committee and other stakeholders descriptions of the below 200 kV reliability violations that will not be included in a proposal window pursuant to the Operating Agreement, Schedule 6, section 1.5.8(c). The descriptions shall include an explanation of the decision to not include the below 200 kV reliability violation(s) in Operating Agreement, Schedule 6, section 1.5.8(c) proposal window, a description of the facility on which the violation(s) is found, the Zone in which the facility is located, and notice that such construction responsibility for and ownership of the project that resolves such below 200 kV reliability violation will be designated to the incumbent Transmission Owner. After the descriptions are posted on the PJM website, stakeholders shall have reasonable opportunity to provide comments for consideration by the Office of the Interconnection. With the exception of Immediate-need Reliability Projects under the Operating Agreement, Schedule 6, section 1.5.8(m), PJM will not select an above 200 kV solution for inclusion in the recommended plan that would address a reliability violation on a below 200 kV transmission facility without posting the violation for inclusion in a proposal window consistent with the Operating Agreement, Schedule 6, section 1.5.8(c). All written comments received by the Office of the Interconnection shall be publicly available on the PJM website.

(o) **[Reserved]**

(p) **Thermal Reliability Violations on Transmission Substation Equipment.** Pursuant to the regional transmission expansion planning process set forth in the Operating Agreement, Schedule 6, sections 1.5.1 through 1.5.6, the Office of the Interconnection shall identify thermal reliability violations on existing transmission substation equipment. The Office of the Interconnection shall not post such thermal reliability violations pursuant to the Operating Agreement, Schedule 6, section 1.5.8(b) for inclusion in a proposal window pursuant to the Operating Agreement, Schedule 6, section 1.5.8(c) if the Office of the Interconnection determines that the reliability violations would be more efficiently addressed by an upgrade to replace in kind transmission substation equipment with higher rated equipment, excluding power transmission transformers, but including station service transformers and instrument transformers. If the Office of the Interconnection determines that the reliability violation does not meet the exemption stated above, the Office of the Interconnection shall post on the PJM website the reliability violations to be included in a proposal window consistent with the Operating Agreement, Schedule 6, section 1.5.8(c). If the Office of the Interconnection determines that the identified thermal reliability violations satisfy the above exemption to the proposal window process, the Office of the Interconnection shall post on the PJM website for review and comment by the Transmission Expansion Advisory Committee and other stakeholders descriptions of the transmission substation equipment thermal reliability violations that will not be included in a proposal window pursuant to Operating Agreement, Schedule 6, section 1.5.8(c). The descriptions shall include an explanation of the decision to not include the

transmission substation equipment thermal reliability violation(s) in Operating Agreement, Schedule 6, section 1.5.8(c) proposal window, a description of the facility on which the thermal violation(s) is found, the Zone in which the facility is located, and notice that such construction responsibility for and ownership of the project that resolves such transmission substation equipment thermal violations will be designated to the incumbent Transmission Owner. After the descriptions are posted on the PJM website, stakeholders shall have reasonable opportunity to provide comments for consideration by the Office of the Interconnection. All written comments received by the Office of the Interconnection shall be publicly available on the PJM website.

1.5.9 State Agreement Approach.

(a) State governmental entities authorized by their respective states, individually or jointly, may agree voluntarily to be responsible for the allocation of all costs of a proposed transmission expansion or enhancement that addresses state Public Policy Requirements identified or accepted by the state(s) in the PJM Region. As determined by the authorized state governmental entities, such transmission enhancements or expansions may be included in the recommended plan, either as a (i) Supplemental Project or (ii) state public policy project, which is a transmission enhancement or expansion, the costs of which will be recovered pursuant to a FERC-accepted cost allocation proposed by agreement of one or more states and voluntarily agreed to by those state(s). All costs related to a state public policy project or Supplemental Project included in the Regional Transmission Expansion Plan to address state Public Policy Requirements pursuant to this Section shall be recovered from customers in a state(s) in the PJM Region that agrees to be responsible for the projects. No such costs shall be recovered from customers in a state that did not agree to be responsible for such cost allocation. A state public policy project will be included in the Regional Transmission Expansion Plan for cost allocation purposes only if there is an associated FERC-accepted allocation permitting recovery of the costs of the state public policy project consistent with this Section.

(b) Subject to any designation reserved for Transmission Owners in the Operating Agreement, Schedule 6, section 1.5.8(l), the state(s) responsible for cost allocation for a Supplemental Project or a state public policy project in accordance with the Operating Agreement, Schedule 6, section 1.5.9(a) may submit to the Office of the Interconnection the entity(ies) to construct, own, operate and maintain the state public policy project from a list of entities supplied by the Office of the Interconnection that pre-qualified to be Designated Entities pursuant to the Operating Agreement, Schedule 6, section 1.5.8(a).

1.5.10 Multi-Driver Project.

(a) When a proposal submitted by an existing Transmission Owner or Nonincumbent Developer pursuant to Operating Agreement, Schedule 6, section 1.5.8(c) meets the definition of a Multi-Driver Project and is designated to be included in the Regional Transmission Expansion Plan for purposes of cost allocation, the Office of the Interconnection shall designate the Designated Entity for the project as follows: (i) if the Multi-Driver Project does not contain a state Public Policy Requirement component, the Office of the Interconnection shall designate the Designated Entity pursuant to the criteria in the Operating Agreement, Schedule 6, section 1.5.8; or (ii) if the Multi-Driver Project contains a state Public Policy Requirement component, the

Office of the Interconnection shall evaluate potential Designated Entity candidates based on the criteria in the Operating Agreement, Schedule 6, section 1.5.8, and provide its evaluation to and elicit feedback from the sponsoring state governmental entities responsible for allocation of all costs of the proposed state Public Policy Requirement component ("state governmental entity(ies)") regarding its evaluation. Based on its evaluation of the Operating Agreement, Schedule 6, section 1.5.8 criteria and consideration of the feedback from the sponsoring state governmental entity(ies), the Office of the Interconnection shall designate the Designated Entity for the Multi-Driver Project and notify such entity consistent with the Operating Agreement, Schedule 6, section 1.5.8(i). A Multi-Driver Project may be based on proposals that consist of (1) newly proposed transmission enhancements or expansions; (2) additions to, or modifications of, transmission enhancements or expansions already selected for inclusion in the Regional Transmission Expansion Plan; and/or (3) one or more transmission enhancements or expansions already selected for inclusion in the Regional Transmission Expansion Plan.

(b) A Multi-Driver Project may contain an enhancement or expansion that addresses a state Public Policy Requirement component only if it meets the requirements set forth in the Operating Agreement, Schedule 6, section 1.5.9(a) and its cost allocations are established consistent with the Tariff, Schedule 12, section (b)(xii)(B).

(c) If a state governmental entity(ies) desires to include a Public Policy Requirement component after an enhancement or expansion has been included in the Regional Transmission Expansion Plan, the Office of the Interconnection may re-evaluate the relevant reliability-based enhancement or expansion, Economic-based Enhancement or Expansion, or Multi-Driver Project to determine whether adding the state-sponsored Public Policy Requirement component would create a more cost effective or efficient solution to system conditions. If the Office of the Interconnection determines that adding the state-sponsored Public Policy Requirement component to an enhancement or expansion already included in the Regional Transmission Expansion Plan would result in a more cost effective or efficient solution, the state-sponsored Public Policy Requirement component may be included in the relevant enhancement or expansion, provided all of the requirements of the Operating Agreement, Schedule 6, section 1.5.10(b) are met, and cost allocations are established consistent with the Tariff, Schedule 12, section (b)(xii)(B).

(d) If, subsequent to the inclusion in the Regional Transmission Expansion Plan of a Multi-Driver Project that contains a state Public Policy Requirement component, a state governmental entity(ies) withdraws its support of the Public Policy Requirement component of a Multi-Driver Project, then: (i) the Office of the Interconnection shall re-evaluate the need for the remaining components of the Multi-Driver Project without the state Public Policy Requirement component, remove the Multi-Driver Project from the Regional Transmission Expansion Plan, or replace the Multi-Driver Project with an enhancement or expansion that addresses remaining reliability or economic system needs; (ii) if the Multi-Driver Project is retained in the Regional Transmission Expansion Plan without the state Public Policy Requirement component, the costs of the remaining components will be allocated in accordance with the Tariff, Schedule 12; (iii) if more than one state is responsible for the costs apportioned to the state Public Policy Requirement component of the Multi-Driver Project, the remaining state governmental entity(ies) shall have the option to continue supporting the state Public Policy component of the

Multi-Driver Project and if the remaining state governmental entity(ies) choose this option, the apportionment of the state Public Policy Requirement component will remain in place and the remaining state governmental entity(ies) shall agree upon their respective apportionments; (iv) if a Multi-Driver Project must be retained in the Regional Transmission Expansion Plan and completed with the State Public Policy component, the state Public Policy Requirement apportionment will remain in place and the withdrawing state governmental entity(ies) shall continue to be responsible for its/their share of the FERC-accepted cost allocations as filed pursuant to the Tariff, Schedule 12, section (b)(xii)(B).

(e) The actual costs of a Multi-Driver Project shall be apportioned to the different components (reliability-based enhancement or expansion, Economic-based Enhancement or Expansion and/or Public Policy Requirement) based on the initial estimated costs of the Multi-Driver Project in accordance with the methodology set forth in the Tariff, Schedule 12.

(f) The benefit metric calculation used for evaluating the market efficiency component of a Multi-Driver Project will be based on the final voltage of the Multi-Driver Project using the Benefit/Cost Ratio calculation set forth in the Operating Agreement, Schedule 6, section 1.5.7(d) where the Cost component of the calculation is the present value of the estimated cost of the enhancement apportioned to the market efficiency component of the Multi-Driver Project for each of the first 15 years of the life of the enhancement or expansion.

(g) Except as provided to the contrary in this Operating Agreement, Schedule 6, section 1.5.10 and Operating Agreement, Schedule 6, section 1.5.8 applies to Multi-Driver Projects.

(h) The Office of the Interconnection shall determine whether a proposal(s) meets the definition of a Multi-Driver Project by identifying a more efficient or cost effective solution that uses one of the following methods: (i) combining separate solutions that address reliability, economics and/or public policy into a single transmission enhancement or expansion that incorporates separate drivers into one Multi-Driver Project ("Proportional Multi-Driver Method"); or (ii) expanding or enhancing a proposed single driver solution to include one or more additional component(s) to address a combination of reliability, economic and/or public policy drivers ("Incremental Multi-Driver Method").

(i) In determining whether a Multi-Driver Project may be designated to more than one entity, PJM shall consider whether: (i) the project consists of separable transmission elements, which are physically discrete transmission components, such as, but not limited to, a transformer, static var compensator or definable linear segment of a transmission line, that can be designated individually to a Designated Entity to construct and own and/or finance; and (ii) each entity satisfies the criteria set forth in the Operating Agreement, Schedule 6, section 1.5.8(f). Separable transmission elements that qualify as Transmission Owner Upgrades shall be designated to the Transmission Owner in the Zone in which the facility will be located.

1.6 Approval of the Final Regional Transmission Expansion Plan.

(a) Based on the studies and analyses performed by the Office of the Interconnection under Operating Agreement, Schedule 6, the PJM Board shall approve the Regional Transmission Expansion Plan in accordance with the requirements of Operating Agreement, Schedule 6. The PJM Board shall approve the cost allocations for transmission enhancements and expansions consistent with Tariff, Schedule 12. Supplemental Projects shall be integrated into the Regional Transmission Expansion Plan approved by the PJM Board but shall not be included for cost allocation purposes.

(b) The Office of the Interconnection shall publish the current, approved Regional Transmission Expansion Plan on the PJM Internet site. Within 30 days after each occasion when the PJM Board approves a Regional Transmission Expansion Plan, or an addition to such a plan, that designates one or more Transmission Owner(s) or Designated Entity(ies) to construct such expansion or enhancement, the Office of the Interconnection shall file with FERC a report identifying the expansion or enhancement, its estimated cost, the entity or entities that will be responsible for constructing and owning or financing the project, and the market participants designated under Operating Agreement, Schedule 6, section 1.5.6(l) to bear responsibility for the costs of the project.

(**c**) If a Regional Transmission Expansion Plan is not approved, or if the transmission service requested by any entity is not included in an approved Regional Transmission Expansion Plan, nothing herein shall limit in any way the right of any entity to seek relief pursuant to the provisions of Section 211 of the Federal Power Act.

(d) Following PJM Board approval, the final Regional Transmission Expansion Plan shall be documented, posted publicly and provided to the Applicable Regional Entities.

1.7 Obligation to Build.

(a) Subject to the requirements of applicable law, government regulations and approvals, including, without limitation, requirements to obtain any necessary state or local siting, construction and operating permits, to the availability of required financing, to the ability to acquire necessary right-of-way, and to the right to recover, pursuant to appropriate financial arrangements and tariffs or contracts, all reasonably incurred costs, plus a reasonable return on investment, Transmission Owners or Designated Entities designated as the appropriate entities to construct, own and/or finance enhancements or expansions specified in the Regional Transmission Expansion Plan shall construct, own and/or finance such facilities or enter into appropriate contracts to fulfill such obligations. Except as provided in Operating Agreement, Schedule 6, section 1.5.8(k), nothing herein shall require any Transmission Owner to construct, finance or own any enhancements or expansions specified in the Regional Transmission Expansion Plan for which the plan designates an entity other than a Transmission Owner as the appropriate entity to construct, own and/or finance such enhancements or expansions.

(b) Nothing herein shall prohibit any Transmission Owner from seeking to recover the cost of enhancements or expansions on an incremental cost basis or from seeking approval of such rate treatment from any regulatory agency with jurisdiction over such rates.

(c) The Office of the Interconnection shall be obligated to collect on behalf of the Transmission Owner(s) or Designated Entity(ies) all charges established under Tariff, Schedule 12 in connection with facilities which the Office of the Interconnection designates one or more Transmission Owners or Designated Entity(ies) to build pursuant to this Regional Transmission Expansion Planning Protocol. Such charges shall compensate the Transmission Owner(s) or Designated Entity(ies) for all costs related to such RTEP facilities under a FERC-approved rate and will include any FERC-approved incentives.

(d) In the event that a Transmission Owner declines to construct an economic transmission enhancement or expansion developed under sections 1.5.6(d) and 1.5.7 of this Schedule 6 that such Transmission Owner is designated by the Regional Transmission Expansion Plan to construct (in whole or in part), the Office of the Interconnection shall promptly file with the FERC a report on the results of the pertinent economic planning process in order to permit the FERC to determine what action, if any, it should take.

1.8 Interregional Expansions

(a) PJM shall collect from Midwest Independent System Operator, Inc., for distribution to the applicable Transmission Owners, in accordance with Schedule 12 of the PJM Tariff, revenues collected by the Midwest Independent System Operator, Inc. under the Open Access Transmission Tariff of the Midwest Independent System Owner, Inc. with respect to transmission enhancements or expansions for which the Coordinated System Plan developed under the Joint Operating Agreement Between the Midwest Independent System Operator, Inc. and PJM Interconnection, L.L.C. assigns cost responsibility for transmission enhancements or expansions in the PJM Region to market participants in the region of the Midwest Independent System Operator, Inc.

(b) PJM shall disburse to the Midwest Independent System Operator, Inc., for distribution to applicable transmission owners of the Midwest Independent System Operator, Inc., revenues collected under Schedule 12 of the PJM Tariff which establishes a charge in connection with enhancements or expansions in the region of the Midwest Independent System Operator, Inc. the cost responsibility for which has been assigned to market participants in the PJM Region under the Coordinated System Plan developed under the Joint Operating Agreement Between the Midwest Independent System Operator, Inc. and PJM Interconnection, L.L.C.

(c) Nothing in this Section 1.8 shall affect or limit any Transmission Owners filing rights under Section 205 of the Federal Power Act as set forth in the PJM Tariff and applicable agreements.

1.9 Relationship to the PJM Open Access Transmission Tariff.

Nothing herein shall modify the rights and obligations of an Eligible Customer or a Transmission Customer with respect to required studies and completion of necessary enhancements or expansions. An Eligible Customer or Transmission Customer electing to follow the procedures in the PJM Tariff instead of the procedures provided herein, shall also be responsible for the related costs. The enhancement and expansion study process under this Protocol shall be funded as a part of the operating budget of the Office of the Interconnection.

EXHIBIT NO. 52

PJM Manual 14B:

PJM Region Transmission Planning Process

Revision: 56

Effective Date: June 27, 2024

Prepared By
Transmission Planning Department

PJM © 2024

Table of Contents

Approval 4

Current Revision 5

Introduction 6

About PJM Manuals 6
About This Manual 6
Using This Manual 7

Section 1A: Critical Energy Infrastructure Information (CEII) 9

1A.1 CEII Definition 9
1A.2 Introduction 9
1A.3 PJM CEII Rules 10

Section 1: Process Overview 13

1.1 Planning Process Work Flow 13
1.2 TEAC and Subregional RTEP Committee and Related Activities 16
1.3 Planning Assumptions and Model Development 18
1.4 RTEP Process Key Components 20
1.5 Planning Criteria 26

Section 2: Regional Transmission Expansion Plan Process 29

2.1 Transmission Planning = Reliability Planning + Market Efficiency+ FERC Form No. 715 + Public Policy + Supplemental Project Planning 29
2.2 The RTEP Process Drivers 35
2.3 RTEP Reliability Planning 38
2.4 RTEP integrates Baseline Assumptions, Reliability Upgrades and Request Evaluations 51
2.5 RTEP Cost Responsibility for Required Enhancements 52
2.6 RTEP Market Efficiency Planning 53
2.7 Evaluation of Operational Performance Issues 59
2.8 End of Useful Life Issues 61
2.9 Critical Substation Planning Analysis 61

Attachment A: PJM Baseline Reliability Upgrade Cost Allocation Procedures 63

A.1 Purpose 63

A.2 Scope 63

A.3 Schedule 12 Cost Allocation Process for Baseline Transmission Reliability Upgrades 63

Attachment B: Regional Transmission Expansion Plan—Scope and Procedure 68

B.1 Purpose 68

B.2 Scope 68

B.3 Procedure 70

B.4 Scenario Planning Procedure 74

Attachment C: PJM Deliverability Testing Methods 76

C.1 Introduction 76

C.2 Load Deliverability 77

C.3 Deliverability of Generation 92

C.4 Long-Term Deliverability Analysis 103

Attachment D: PJM Reliability Planning Criteria 109

Attachment D-1: Load Loss Definitions 112

Attachment E: Market Efficiency Analysis Economic Benefit / Cost Ratio Threshold Test 114

E.1 Total Annual Enhancement Benefit 114

E.2 Total Annual Enhancement Cost 116

Attachment F: Determination of System Operating Limits used for planning the Bulk Electric System 117

Attachment G: PJM Stability, Short Circuit and Special RTEP Practices and Procedures 122

G.1 Stability 122
G.2 Dynamics Procedures 123
G.3 New Service Request Stability Study Procedures 127
G.4 System Stability Studies 129
G.5 Impact Study Procedures Applicable to Wind Turbine Analyses 132
G.6 Stability Analyses of Stability Sensitive Local Areas in PJM 134
G.7 Short Circuit 134
G.8 Nuclear Plant Specific Impact Study Procedures 135
G.9 Appendix to Manual 14B Attachment G 136
G.10 NERC Standard PRC-023 – Transmission Relay Loadability 140
G.11 PJM Capacity Import Limit Calculation Procedure 142
G.12 NERC Standard FAC-002 – Facility Interconnection Studies 145

Attachment H: Power System Modeling Data 147

H.1 Power System Modeling Data 147

Attachment I: Steady State & Stability Performance Planning Events 156

Attachment J: Checklist for New Equipment Energization Process 163

Attachment K: CIR for ELCC Transition 166

Revision History 169

Approval

Approval Date: 06/28/2024
Effective Date: 06/27/2024

Sami Abdulsalam, Sr. Manager

Transmission Planning

Current Revision

Revision 56 (06/27/2024):

- Added clarifications to sections C.2.1.4, C.2.4, and C.2.5 that reflect the changes to the calculation of CETO and reliability targets based on the FERC approved docket ER24-99.
- Conforming changes were made to the following sections to incorporate provisions of FERC's CIFP-RA order (ER24-99):
- C.2.1.4 General Procedures
- C.2.4 Capacity Emergency Transfer Objective (CETO) Procedure
- C.2.5 Capacity Emergency Transfer Limit (CETL) Procedure

Introduction

Welcome to the **PJM Region Transmission Planning Process Manual.** In this Introductory Section you will find information about PJM manuals in general, an overview of this PJM Manual in particular and information on how to use this manual.

About PJM Manuals

The PJM Manuals are the instructions, rules, procedures, and guidelines established by PJM 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
- PJM Regional Transmission Expansion
- Reserve
- Accounting and billing
- PJM administrative services

For a complete list of all PJM manuals, go to the Library section on PJM.com.

About This Manual

The **PJM Region Transmission Planning Process Manual** is one of the PJM manuals in the PJM Regional Transmission Expansion group. This manual focuses on the process for planning baseline expansion facilities under the PJM Region Transmission Planning Process. Capitalized terms not defined as they are used have the meaning defined in the PJM's Open Access Transmission Tariff (OATT) and in the Operating Agreement (OA.)

This **PJM Region Transmission Planning Process Manual** consists of two sections and related attachments. All sections and attachments are listed in the Table of Contents.

Note:
While the PJM Manuals provide instructions and summaries of the various rules, procedures and guidelines for all phases of PJM's planning process, the PJM Operating Agreement and the PJM Open Access Transmission Tariff (OATT) contain the authoritative provisions.

Intended Audience

The intended audiences for this PJM Region Transmission Planning Process Manual include:

- Generation and Transmission Project Developers and their engineering staff

Note:
Prior to the Transition Date, the Interconnection Service Agreement (ISA) was the form agreement included in the Tariff used to facilitate interconnection to PJM's transmission system, which used term "Interconnection Customer" to refer to generation interconnection customers, similar to the Project Developer. While the ISA is no longer used for interconnection to the transmission system, pre-existing ISAs remain active. On and after the Transition Date, the Generation Interconnection Agreement (GIA) is used as the form agreement included in the Tariff to facilitate interconnection to PJM's transmission system.

The Tariff defines the Transition Date as the later of: (i) the effective date of PJM's Docket No. ER22-2110 transition cycle filing seeking FERC acceptance of Tariff, Part VII (which is January 3, 2023) or (ii) the date by which all AD2 and prior queue window Interconnection Service Agreements or wholesale market participation agreements have been executed or filed unexecuted. Because this second condition happened last, this date establishes the Transition Date.

- Transmission Owners and their respective engineering staff
- Federal and state regulatory bodies
- PJM Members
- PJM staff

References

There are other PJM documents that provide both background and detail on specific topics that may be related to topics in this manual. References with related information include:

- PJM Manual 1: *Control Center and Data Exchange Requirements*
- PJM Manual 2: *Transmission Service Request*
- PJM Manual 3: *Transmission Operations*
- PJM Manual 14A: *Generation and Transmission Interconnection Process*
- PJM Manual 14C: *Generation and Transmission Interconnection Facility Construction*
- PJM Manual 14D: *Generator Operational Requirements*
- PJM Manual 14E: *Merchant Transmission Specific Requirements*
- PJM Manual 14H: New Service Request Process
- PJM Manual 21: *Rules and Procedures for Determination of Generating Capability*

Using This Manual

We believe that explaining concepts is just as important as presenting 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 manuals' structure.

What You Will Find In This Manual

- A table of contents.
- An approval page that lists the required approvals and a brief outline of the current revision.
- This Introduction and sections containing the specific transmission planning process details including assumptions, criteria, procedures and stakeholder interactions.
- Attachments that include additional supporting documents, forms, or tables.
- A section at the end detailing all previous revisions of this PJM Manual.

Section 1A: Critical Energy Infrastructure Information (CEII)

1A.1 CEII Definition

PJM adopts the Federal Energy Regulatory Commission's ("FERC" or "Commission") definitions of Critical Energy Infrastructure Information ("CEII") and Critical Infrastructure at 18 CFR §388.113 (c) as follows:

- Critical Energy Infrastructure Information means specific engineering, vulnerability, or detailed design information about proposed or existing critical infrastructure that:
  - Relates details about the production, generation, transportation, transmission, or distribution of energy;
  - Could be useful to a person in planning an attack on critical infrastructure;
  - Is exempt from mandatory disclosure under the Freedom of Information Act, 5 U.S.C. 552; and
  - Does not simply give the general location of the critical infrastructure.
- Critical Infrastructure means existing and proposed systems and assets, whether physical or virtual, the incapacity or destruction of which would negatively affect security, economic security, public health or safety, or any combination of those matters.

1A.2 Introduction

1A.2.1 General Intent

PJM's intent is to provide a process for eligible recipients to access CEII consistent with the Commission's standards for handling CEII material. PJM information that contains CEII can only be obtained by complying with PJM's CEII authorization process.

1A.2.2 Examples of CEII

The Commission considers certain information to be CEII. For example, information filed in the FERC-715, Part 2, Part 3, and Part 6 (http://www.ferc.gov/legal/ceii-foia/ceii.asp) is considered by the FERC to be CEII. This information contains electrical models, detailed one-line diagrams and analysis of the filer's actual transmission system including potential weaknesses of the filer's transmission system. PJM treats all such power flow and associated system modeling data as CEII. This includes all power flow models that are developed using or including data and related information used in transmission system analysis such as contingency and monitored element files. Power flows specifically configured for short circuit analysis that do not contain load and generation dispatch are not considered CEII. Other information may also qualify as CEII under the Commission's definitions.

1A.2.3 Rules When CEII Includes Confidential Member Information

Regarding all types of PJM information, additional consideration must be given to whether or not PJM received or originated the information as confidential information prior to decisions regarding its release. Confidential information is governed by the PJM Operating Agreement Section 18.17 and the Open Access Transmission Tariff Sections 222-223. Certain information is a combination of CEII information filed or provided by a number of "owners" and may include confidential information. To the extent CEII material sought from PJM includes confidential information of a PJM Member, including PJM Transmission Owners or Generation Owners, PJM will require the requester to demonstrate the affected members give consent to the release of the confidential information contained within the CEII material by PJM to comply with the Tariff and Operating Agreement. Power flows may, but generally do not, contain confidential information. Some PJM power flows are special cases that contain both confidential information and CEII. For example, PJM power flows originating from system operations and used for near term operational studies often contain confidential information in addition to CEII. Confidential information of members, if any, may be redacted prior to release of CEII if the CEII requester is unable to demonstrate to PJM that the affected members give consent to the release of the confidential material.

1A.2.4 Reservation of Rights to Amend CEII Rules

PJM reserves the right to revise its process from time-to-time, to limit access to CEII as may be appropriate in any specific instance in accordance with PJM's manual revision procedures posted on PJM.com.

1A.3 PJM CEII Rules

1A.3.1 CATEGORIES OF PJM CEII REQUESTERS PROCEDURES

1A.3.1.1 Authorized Entities Procedures

The process to request CEII from PJM is as follows for an employee or authorized agent/ consultant of : (i) a PJM Member; (ii) a PJM Transmission Owner; (iii) a PJM Generation Owner or operator of generating units in the PJM Region; (iv) a NERC registered Transmission Owner/ Operator; (v) a PJM Project Developer; (vi) another RTO or similar independent system operator recognized by the Federal Energy Regulatory Commission; (vii) a NERC Planning Coordinator or Transmission Planner; (viii) a Non-incumbent Developer pre-qualified to be a Designated Entity pursuant to Schedule 6 of the Operating Agreement; or (viii) a natural gas local distribution company and/or a natural gas pipeline operator serving customers within the PJM Region (individually "Authorized Entity" and together "Authorized Entities"). The process outlined below allows for individual employees or individual authorized consultants of Authorized Entities to obtain CEII. PJM's procedures set forth below allow an organization to submit requests on behalf of multiple individuals within Authorized Entities.

Except in the case of Organizational CEII requests described below, each individual requester of CEII from employees or authorized agents/consultants of Authorized Entities must complete a PJM CEII Request Form and must execute the appropriate PJM CEII Nondisclosure Agreement ("NDA"). Employee, authorized agent or an Authorized Entity must submit a PJM CEII Authorization Form (in addition to the requester's completed PJM CEII Request Form and appropriate PJM CEII NDA) that identifies each individual agent/consultant who may make individual requests for PJM CEII on behalf of such entity.

Once the CEII requester has been verified by PJM as a legitimate CEII requester (i.e., a legitimate employee or authorized consultant of one of the organizations listed in paragraph 1A.3.1.1 above), such CEII requester may obtain CEII.

Organizational CEII Requests: Authorized Entities may enter into an organizational agreement with PJM which will allow the receiving organization to share CEII information under the terms of an applicable PJM CEII NDA however, PJM may use other forms of organizational CEII NDAs as appropriate. Such organizational NDA will require individual recipients of CEII material to be listed and sign an attachment to the NDA which will require each individual to acknowledge his or her understanding of the restrictions on the use of CEII or further disclosures except as allowed under the terms of the organizational NDA. Each organization is required to keep the list of authorized individual recipients up to date and notify in PJM in writing of any changes to the status of the authorized individual recipients in accordance with the applicable NDA.

1A.3.1.2 Federal Agency and NERC Procedures

If the requester of CEII material is a representative of FERC, Department of Energy, Department of Homeland Security, NERC or a NERC Regional Entity (e.g. RF, SERC, etc.), PJM will release the information if PJM confirms that the requestor (requestors) are employees of these agencies and the CEII material is subject to the agencies rules of procedures applicable to CEII.

1A.3.1.3 PJM Authorized State Commission

The process to request CEII from PJM is as follows for an employee of a PJM Authorized State Commission: Each individual requester of CEII must complete a PJM CEII Request Form and must execute a PJM CEII Government NDA located on the PJM website.

- After such CEII requester has been verified by PJM as a legitimate CEII requester (i.e., a legitimate employee of one of the governmental organizations listed above), such CEII requester may obtain the requested CEII.

1A.3.1.4 Procedures Applicable to Other CEII Requests

The process to request CEII from PJM is as follows for any other requester seeking CEII from PJM:

- Each individual requester of CEII must establish or have a PJM.com account. A PJM.com account can be created here: https://accountmanager.pjm.com/accountmanager/pages/public/new-user.jsf
- Each individual requester of CEII must then complete a PJM CEII Request Form and must execute an appropriate PJM CEII NDA. The PJM CEII NDA form will come up when a link to CEII is clicked on many places on PJM.com. There are prepopulated PJM CEII Request Forms at various locations throughout PJM.com. A blank generic PJM CEII Request Form is located at: https://www.pjm.com/library/request-access.aspx. Where the individual requester of CEII is an authorized agent/consultant for another entity, then an authorized employee of such entity must submit a PJM CEII Authorization Form (in addition to the requester's completed PJM CEII Request Form and the appropriate PJM CEII NDA) that identifies each individual agent(s)/consultant(s) who may make individual requests for PJM CEII on behalf of such entity. The PJM CEII Authorization Form is located on the PJM website at: https://www.pjm.com/library/request-access/form-ceii-consultant-request.aspx
- Upon receiving all completed required CEII forms, PJM will determine if the requested information is CEII, and, if it is, whether to release the CEII to the requester. PJM will use the information provided by the requester in the PJM CEII Request Form to (1) establish whether a requester has presented a legitimate need for the CEII; and (2) weigh the need for the CEII against the potential harmful effects of its release. In reviewing the request from such individual, PJM will confirm the authenticity of the CEII requester and whether the request is consistent with the requestor's business or educational interest as determined from a review of publicly available data such as the requestor's website. If PJM is unable to determine from publicly available information that the request is consistent with the requestor's business or educational interest in such data, the request will be denied. A requester shall provide additional information (beyond the PJM CEII Request Form) to PJM upon PJM's request.

1A.3.2 PJM CEII Handling

A recipient of PJM CEII shall maintain it in a secure place. Access to PJM CEII shall be limited to the recipient and other recipients of the identical CEII. Recipients may make copies of PJM CEII, but such copies are PJM CEII and subject to the same required handling. Recipient may make notes regarding the PJM CEII, but those notes shall be treated as PJM CEII notes if they contain CEII or were derived from PJM CEII.

Section 1: Process Overview

In this section you will find an overview of PJM's transmission planning process that culminates in the Regional Transmission Expansion Plan (RTEP). This process (referred to in this Manual interchangeably as the RTEP process or more generically as the PJM regional transmission planning process) is one of the primary functions of Regional Transmission Organizations (RTOs.) As such, PJM implements this function in accordance with the Regional Transmission Expansion Planning Protocol set forth in Schedule 6 of the PJM Operating Agreement.

As further described in following portions of this manual, the PJM RTEP process consists of baseline reliability reviews as well as analysis to identify the transmission needs associated with generation interconnection and merchant transmission interconnection. PJM implements the planning of interconnections as part of the broader RTEP process pursuant to the PJM Open Access Transmission Tariff (OATT.) The relationship between Interconnection planning and the RTEP is discussed in later sections of this manual and in related manuals.

1.1 Planning Process Work Flow

The Manual 14 series provides information regarding PJM's regional transmission expansion planning protocol (RTEPP) to complement planning provisions in the PJM Operating Agreement, Schedule 6 and the PJM Open Access Transmission Tariff (OATT), Attachment M-3 (Attachment M-3 Process). These agreements can be found on-line at https://www.pjm.com/library/governing-documents.aspx.

This ongoing process has continued to evolve since 1997, when PJM's RTEPP (codified in PJM's Operating Agreement, Schedule 6) was approved by the Federal Energy Regulatory Commission (FERC). Since that time, the process has been expanded and enhanced in response to member and regulatory input as documented in the Operating Agreement, Schedule 6; OATT, Attachment M-3; and the PJM Manual 14 series. The current PJM regional transmission expansion plan (RTEP) process includes ample opportunity for stakeholder input through frequent oral and written exchange of information and reviews via the Transmission Expansion Advisory Committee (TEAC) and PJM's three (3) Subregional RTEP Committees (Mid-Atlantic, Southern and Western).

PJM and PJM Transmission Owners' planning processes are incorporated in an 18-month overlapping planning cycle which begins in September of the previous calendar year and extends through a full calendar year to the February of the next calendar year. This overlapping planning cycle is illustrated in Exhibit 1 in this Manual.

The PJM planning process activities, culminating in PJM's annual RTEP, constitute PJM's single, Order No. 890 compliant, transmission planning process.

All PJM OATT facilities are planned through and included in this open, fully participatory, and transparent process.

There are three (3) planning paths that ultimately culminate in the PJM RTEP base case, also referred to as the planning model. Facilities identified in each path allow for the opportunity for early, full and transparent participation by interested PJM stakeholders. The three paths include planning activities associated with: (i) Regional RTEP Project and Subregional RTEP Project (baseline upgrades), (ii) Supplemental Projects; and (iii) Customer-Funded Upgrades. Baseline upgrades include projects planned for (i) reliability, (ii) operational performance, (iii) FERC Form No. 715 criteria, (iv) economic planning, and (v) public policy planning (State Agreement Approach). Supplemental Projects refer to transmission expansion or enhancements not needed to comply with PJM reliability, operational performance, FERC Form No. 715, economic criteria or State Agreement Approach projects; Supplemental Project drivers, or needs, are "supplemental" to those Operating Agreement specified criteria. Transmission Owners plan Supplemental Projects in accordance with the OATT, Attachment M-3 Process. Projects planned through the Attachment M-3 Process include those that expand or enhance the transmission system. By way of example, a Supplemental Project could include a Transmission Owner project needed to address transmission facilities at the end of their useful life, which, in accordance with good utility practice, is not determined by the facility's service life for accounting or depreciation purposes. Customer-Funded Upgrades refer to Network Upgrades, Distribution Upgrades or Merchant Network Upgrades identified pursuant to OATT Parts II, III and VIII and paid for by the Project Developer or Eligible Customer or voluntarily undertaken by an Upgrade Customer in fulfillment of an Upgrade Request.

Planning of Baseline Upgrades:

Baseline upgrades are produced from PJM's planning Cycle activities described in this manual, Operating Agreement Schedule 6, and illustrated in Exhibit 1 in this Manual. PJM leads the analysis and development of baseline upgrades related to reliability , operational performance, FERC Form No. 715 criteria and economic planning for all facilities 100 kV and above under PJM's operational control. These facilities are designated as Bulk Electric System (BES) facilities and are subject to the North American Electric Reliability Corporation (NERC) standards and criteria for such facilities. The PJM analyses ensure compliance with NERC, PJM and any applicable Regional Entity criteria (e.g. Reliability First (RF) or SERC Reliability Corporation (SERC)). In addition, the PJM-led analyses also include analysis of and solutions for transmission facilities with nominal voltages below 100kV to the extent such facilities are under PJM's operational control (see http://www.pjm.com/markets-and-operations/ops-analysis/transmission-facilities.aspx). The TEAC and Subregional RTEP Committees provide the opportunity for stakeholders to engage in the PJM transmission planning process of such facilities, as described in this Manual.

In addition, for transmission facilities under PJM operational control, the Transmission Owner may submit its local planning criteria in its FERC Form No. 715 filing.

Transmission Owner Supplemental Projects:

Supplemental Projects refer to a transmission expansion or enhancement not needed to comply with PJM reliability, operational performance, FERC Form No. 715 or economic criteria. Transmission Owners plan Supplemental Projects in accordance with the Attachment M-3 Process. Projects planned through the Attachment M-3 Process could include those that: (i) expand or enhance the transmission system; (ii) address Transmission Owner zonal reliability issues; (iii) maintain the existing transmission system; (iv) comply with regulatory requirements or (v) implement Transmission Owner asset management activities (which could include needs related to a transmission facility approaching the end of its useful life, which, in accordance with good utility practice, is not determined by the facility's service life for accounting or depreciation purposes).

Pursuant to the Attachment M-3 Process, Supplemental Projects are presented through the TEAC (230 kV and above facilities) or the Subregional RTEP Committees (below 230 kV facilities) for review and comment in a three-part meeting process that includes at a minimum (i) an Assumptions Meeting, (ii) a Needs Meeting and (iii) a Solutions Meeting. The Solutions Meetings are followed by a round of comments before the Transmission Owners finalize the Supplemental Projects. The stakeholders are provided a final comment period before the Supplemental Project is included in the Local Plan. Supplemental Projects included in the Local Plan are provided to the TEAC and the PJM Board as informational before integrating the Supplemental Project into the RTEP base case. Supplemental Projects are not approved by the PJM Board.

It should also be noted that prior to integrating a Supplemental Project into the RTEP base case PJM performs a "do no harm study" to evaluate whether a proposed Supplemental Project will adversely impact the reliability of the Transmission System as represented in the planning models used in all other PJM reliability planning studies. If as a result of the do no harm study, system upgrades are required, such upgrades will be considered part of the Supplemental Project and are the responsibility of the Transmission Owner sponsoring the Supplemental Project.

As part of the review of Supplemental Projects, PJM will inform stakeholders if PJM determines that a proposed Supplemental Project does not meet the Operating Agreement definition of a Supplemental Project. Additionally, PJM will monitor the status of the projects being developed through the Attachment M-3 Process in order to associate the Supplemental Project with the need identified by the Transmission Owner in the Attachment M-3 Process. For Supplemental Projects, the transparent identification of the need is important to PJM's regional planning process and, accordingly, the identification of the need should include a description of the need in sufficient detail that together with the applicable criteria and supporting documentation stakeholders are capable of reviewing the Transmission Owner's need determination as well as replicating the results of the planning studies.

A Project proposed as a Supplemental Project that does not meet the definition of Supplemental Project or cannot be associated with the need identified by the Transmission Owner in the Attachment M-3 Process will not be included in the Local Plan. Supplemental Projects, to the extent they are developed through the Attachment M-3 Process and can be associated with a supplemental need(s) identified by the relevant TO, will be included in the next annual RTEP base case.

Through the Attachment M-3 Process, Supplemental Projects are subject to similar open, transparent and participatory PJM committee activities, as are baseline upgrades developed through the TEAC and the Subregional RTEP Committee meetings (see discussion of TEAC and Subregional RTEP Committees).

As part of the review of Supplemental Projects PJM will also apprise the relevant Transmission Owner if a baseline upgrade might alleviate or partially mitigate the need for a Supplemental Project. In addition, PJM will determine if a Supplemental Project might impact a baseline need identified through the RTEP process, which might be in progress. A discussion of guidelines associated with potential for overlapping needs in included in this Manual below in section 1.4.2.

Planning for Customer-Funded Upgrades is performed in response to a New Service Request or Upgrade Request, and includes Network Upgrades, Distribution Upgrades or Merchant Network Upgrades identified pursuant to OATT Parts II, III and VIII. Studies of interconnection and transmission service requests and any resulting transmission modifications are posted to PJM's website in the project Cycle area (http://www.pjm.com/planning/generation-interconnection.aspx). In addition, any necessary transmission facility modifications are brought to the TEAC for presentation and stakeholder participation. Interconnection planning is discussed in more detail in Manual 14H.

1.2 TEAC and Subregional RTEP Committee and Related Activities

The PJM TEAC functions in accordance with its established charter and provisions of the Operating Agreement, Schedule 6. Additionally, in 2008 PJM began to facilitate more localized planning functions through the Subregional RTEP Committees.

The TEAC and Subregional RTEP Committees provide a transparent and participatory planning process throughout the development of the RTEP, from early assumptions-setting stages to discussion of criteria violations and/or identified system needs, review of recommendations for alternative solutions and then review and comment regarding the solutions incorporated into the RTEP base case.

The Subregional RTEP Committees allow more focused and meaningful stakeholder participation and attention to the subregional and local Transmission Owner zonal issues. Currently, there are three PJM RTEP subregions: Mid-Atlantic, Southern, and Western. When a Subregional RTEP Committee meeting is needed and scheduled, it generally will be implemented as a separate meeting for each subregion.

All PJM stakeholders can participate in any or all subregional activities on a voluntary basis, with one exception. The exception is that the Transmission Owners that comprise each of the various subregions must participate in the Subregional RTEP Committee meeting that includes their area and each Transmission Owner must be present at the TEAC meeting where its Supplemental Projects are presented. PJM will facilitate TEAC and Subregional RTEP Committees to review Regional RTEP Projects, Subregional RTEP Projects and Supplemental Projects.

PJM, with stakeholder input, may initiate additional Subregional RTEP Committees meetings consistent with the Attachment M-3 Process to review and address stakeholder questions or concerns regarding needs or proposed solutions, as may be necessary or beneficial. Separate local meetings or more localized reviews may also be held by individual PJM Transmission Owners in the event that the individual Transmission Owner decides that it is a more appropriate way to address local issues. In addition to their participation in the TEAC and Subregional RTEP Committees meetings, stakeholders can also provide written comments on the development of baseline upgrades and Supplemental Projects. Written comments can be provided to PJM through the Planning Community on PJM.com.

For administrative convenience, RTEP projects (i.e., baseline upgrades) are separated into Regional RTEP Projects (230 kV and above) and Subregional RTEP Projects (below 230 kV) (referred to collectively herein as “RTEP Projects”), as defined in the Operating Agreement, in order to make an initial categorization and posting of violations and upgrades that will enable stakeholders to more easily sort through and review issues of interest.

Regional RTEP Projects and Supplemental Projects (230 kV and above) will be reviewed at the TEAC. Subregional RTEP Projects and Supplemental Projects (below 230 kV) will be reviewed at the applicable Subregional RTEP Committee. The Subregional RTEP Committee is responsible for the initial review of Subregional RTEP Projects. For Regional and Subregional RTEP Projects, the TEAC and Subregional RTEP Committees follow the procedure set forth in the Operating Agreement, Schedule 6 specific to the TEAC and other applicable PJM committee procedures. For Supplemental Projects subject to Attachment M-3, the Attachment M-3 Process will apply.

Review of RTEP Projects and Supplemental Projects at the TEAC and/or Subregional RTEP Committees normally occurs during the February through August RTEP stakeholder analysis and review periods (see Exhibit 1). However, additional Supplemental Projects for unforeseen needs that a PJM Transmission Owner identifies later in the year will follow OATT, Attachment M-3 Process for inclusion in the RTEP.

Stakeholders will be provided the information necessary for participation in the discussions and evaluations, including: (1) the PJM and/or Transmission Owners models, criteria and assumptions that underlie transmission system plans, (2) the procedure to access the study information necessary to replicate the PJM and/or Transmission Owner planning studies and participate in the evaluation and discussion of the identified need, (3) information regarding the

project proposed to address the identified need, (4) the current cost estimate for the project, and (5) a description of the proposed modifications to existing facilities that may be part of the project.

In addition, projects that originate through Transmission Owner planning will be posted on the PJM web site. This site will include all currently planned baseline upgrades and newly planned Supplemental Projects and Transmission Owner Initiated projects from past RTEP cycles that are yet to be placed in-service). This website provides tracking information about the status of listed projects and planned in-service dates. It also includes information regarding criteria, assumptions and availability of study cases.

1.3 Planning Assumptions and Model Development

1.3.1 Reliability Planning (including Operational Performance and Public Policy Planning)

PJM's planning analyses are based on a consistent set of fundamental assumptions regarding load, generation and transmission built into power flow models. Load assumptions are based on the annual PJM entity load forecast independently developed by PJM (found at http://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process.aspx.) This forecast includes the basis for all load level assumptions for planning analyses throughout the 15 year planning horizon. Generation and transmission planning assumptions are embodied in the base case power flow models developed annually by PJM and derived from the Eastern Reliability Assessment Group processes and procedures pursuant to NERC standard MOD-032, as well as Transmission Owners' assumptions included in their respective FERC Form No. 715. As necessary, PJM updates its models (e.g., power flow, short circuit, and stability) with the most recent data available for its own regional studies. All PJM base power flow and related information are available pursuant to applicable Critical Energy Infrastructure Information, Non-Disclosure and OATT-related requirements (accessible via http://www.pjm.com/planning/rtep-development/powerflow-cases.aspx or by contacting the PJM Planning Committee contacts.) Each type of RTEP analysis (e.g., load deliverability, generator deliverability etc.) encompasses its own methodological assumptions as further described throughout the rest of this Manual. Additional details regarding the reliability planning criteria, assumptions, and methods can be found in following sections and this manual's Attachments.

Attachment J contains the checklist for the new equipment energization process to be utilized by Transmission Owners and Designated Entities from inception to energization of upgrade projects.

1.3.2 Economic Planning

Each year as part of the 24-Month Market Efficiency Cycle, PJM performs a market efficiency analysis, following the completion of the near- term reliability plan for the region. PJM's market efficiency planning analyses will utilize many of the same starting assumptions applicable to the reliability planning phase of the RTEP development. In addition, key market efficiency input

assumptions, used in the projection of future market inefficiencies; include load and energy forecasts for each PJM zone, fuel costs and emissions costs, expected levels of potential new generation and generation retirements and expected levels of demand response. PJM will input its study assumptions into a commercially available market simulation data model that is available to all stakeholders. The data model contains a detailed representation of the Eastern Interconnection power system generation, transmission and load. In addition, the market efficiency analysis of the cost/benefit of potential market efficiency upgrades will also include the discount rate and annual revenue requirement rate. The discount rate is used to determine the present value of the enhancements' annual benefits and annual cost. The annual revenue requirement rate is used to determine the enhancements' annual cost. PJM will finalize the market efficiency analysis input assumptions soon after the development of the PJM load forecast that is generally available approximately in late January. Prior to finalizing, PJM will review the proposed assumptions at the PJM Transmission Expansion Advisory Committee. This review will provide the opportunity for stakeholder review of and input to all of the key assumptions that form the basis of the market efficiency analysis. In this way, PJM will facilitate a comprehensive stakeholder review and input regarding RTEP study assumptions. All final assumptions and analysis parameters will be presented to the TEAC for discussion and review and to the PJM Board for consideration.

1.3.3 FERC Form No. 715

The Transmission Owner's process specific to the Transmission Owner's zone, including projects that could address the end of useful life of existing facilities, which, in accordance with good utility practice, is not determined by the facility's service life for accounting or depreciation purposes, may be memorialized as Transmission Owner planning criteria under the Transmission Owner's FERC Form No. 715.

1.3.4 Supplemental Projects

Supplemental Projects are included in both PJM and Transmission Owners planning models for the applicable reliability studies conducted outside the Attachment M-3 Process, to the extent the Supplemental Project impacts the transmission system.

The Transmission Owners' planning of Supplemental Projects follows the sequence of steps set out in the Attachment M-3 Process. Commencing September of the year preceding the next RTEP year, PJM will include as part of the model development for the next year's RTEP base case (see 18-month planning cycle illustrated in Exhibit 1 in this Manual), those Supplemental Projects submitted by the Transmission Owners for inclusion in the Local Plans in the July timeframe.

Additional Supplemental Projects for unforeseen needs that a PJM Transmission Owner identifies later in the year, and which are finalized after July, may be included in the base case if the inclusion of these projects would not disrupt analysis associated with the development of the RTEP violations. Such additional Supplemental Projects must comply with the Attachment M-3 Process. Once PJM issues its preliminary RTEP models for verification of topology and dispatch

prior to initiation of any preliminary RTEP analysis and quality control check in preparation for opening a proposal window, PJM will not consider for inclusion in the RTEP base case a subsequently-submitted proposed Supplemental Project(s) that would alleviate a violation identified in the proposal window. However, a Transmission Owner, or any other pre-qualified Designated Entity, may submit a project proposal for consideration in the proposal window to address a posted violation that would also address a related need identified in the Attachment M-3 Process.

1.4 RTEP Process Key Components

PJM's goal is to ensure electric supply adequacy and to enhance the robustness of energy and capacity markets. Achieving these objectives requires the successful completion of PJM's planning, facility construction and operational and market infrastructure requirements.

1.4.1 Key Process Drivers

Key components of PJM's 15-year transmission planning process discussed in this Manual include:

1.4.1.1 Baseline reliability analyses

The PJM Transmission System ("PJM System") provides the means for delivering the output of interconnected generators to the load centers in the PJM energy and capacity markets. Baseline reliability analyses ensure the security and adequacy of the Transmission System to serve all existing and projected long term firm transmission use including existing and projected native load growth as well as long term firm transmission service. RTEP baseline analyses include system voltage and thermal analysis, and stability, load deliverability, and generator deliverability testing. These tests variously entail single and multiple contingency testing for violations of established NERC reliability criteria regarding stability, thermal line loadings and voltage limits. Baseline reliability analyses are discussed in more detail in Section 2 and Attachment C.

1.4.1.2 Economic analyses (Market Efficiency studies)

In addition to reliability based analyses PJM also evaluates the economic merit of proposed transmission enhancements. These analyses focus on the economic impacts of security constraints on production cost, congestion charges to load and other econometric measures of market impacts. PJM's market efficiency analyses are discussed in Section 2 of this Manual and Attachment E. PJM development of economic transmission enhancements is also codified under Schedule 6 of the PJM Operating Agreement.

1.4.1.3 Operational performance issue reviews and accompanying analyses

Maintaining a safe and reliable Transmission System also requires keeping the transmission system equipment in safe, reliable operating condition as well as addressing actual operational needs. On an ongoing basis, PJM operating and planning personnel assess the PJM

transmission development needs based on recent actual operations. This may lead to special studies or programs to address actual system conditions that may not be evident through projections and system modeling.

To ensure that system facilities are maintained and operated to acceptable reliability performance levels, PJM has implemented an Aging Infrastructure Initiative to evaluate appropriate spare transformer levels and optimum equipment replacement or upgrade requirements. This initiative, based on a Probability Risk Assessment (PRA) process, is intended to result in a proactive, PJM-wide approach to assess the risk of facility failures and to mitigate operational and market impacts. Section 2 of this manual provides further discussion of the PRA process.

1.4.1.4 FERC Form No. 715

Each Transmission Owner specifies reliability criteria it uses to evaluate system performance in its FERC Form No. 715 filing. As part of the RTEP process, PJM will identify system needs using each Transmission Owner's planning criteria, which could include end of useful life, which, in accordance with good utility practice, is not determined by the facility's service life for accounting or depreciation purposes and other asset management activities, reflected in the Transmission Owner's FERC Form No. 715.

1.4.1.5 Supplemental Project Planning

Transmission Owner may identify a need associated with a transmission expansion or enhancement not required to comply with the PJM reliability, operational performance, FERC Form No. 715 or economic criteria. The PJM Transmission Owners plan Supplemental Projects in accordance with the Attachment M-3 Process. Projects planned through the Attachment M-3 Process could include those that: (i) expand or enhance the transmission system; (ii) address local reliability issues; (iii) maintain the existing transmission system; (iv) comply with regulatory requirements; or (v) implement Transmission Owner asset management activities (which could include needs related to a transmission facility approaching the end of its useful life, which, in accordance with good utility practice, is not determined by the facility's service life for accounting or depreciation purposes.

1.4.1.6 Customer-Funded Upgrade analyses

A Customer-Funded Upgrade is a Network Upgrade, Distribution Upgrade or Merchant Network Upgrade (Network Upgrade) the cost of which is paid for by a Project Developer, Eligible Customer or Upgrade Customer. All entities requesting interconnection of a generating facility (including increases to the capacity of an existing generating unit) or requesting interconnection of a merchant transmission facility within the PJM region must do so through PJM's interconnection process detailed in OATT, Parts IV and VIII. PJM studies the interconnection and deliverability of New Service Requests or Upgrade Requests in the local area at the Point of Interconnection to determine whether Customer-Funded Upgrades are required to either interconnect to the system or upgrade existing facilities operated by PJM. The interconnection process and deliverability testing procedures are discussed further in this Manual in Attachment

C and Manual 14H. The evaluation of generation and merchant transmission New Service Requests is codified in the Tariff, Parts IV and VIII.

1.4.1.7 The Final RTEP Plan

Based on all of the requirements for firm transmission service on the PJM System, PJM develops an annual RTEP to meet those requirements on a reliable, economic system development and environmentally acceptable basis.

Furthermore, by virtue of its regional scope, the RTEP process assures coordination of expansion plans across multiple transmission owners' systems, permitting the identification of the most efficient or cost-effective expansion plan for the region. The RTEP developed through this process is reviewed and approved by PJM's Board of Managers. The Supplemental Projects are integrated into the RTEP, however the Board does not approve individual Supplemental Projects. The following Section 2 describes the PJM RTEP Process analysis.

1.4.1.8 Maintaining reliability associated with critical substations

To ensure the reliability of the transmission grid into the future, PJM has implemented a set of analysis to further enhance system reliability as discussed in Section 2.9 of this Manual 14B. This study is based on technical analysis performed, such as that performed using the PJM cascading trees tool software, and incorporates standard analytical methods of power flow study. As part of the RTEP process, PJM will analyze all transmission system enhancements to ensure that acceptable critical substation planning analysis objectives are maintained based on the analysis.

1.4.2 Coordination of Baseline Upgrades, Supplemental Projects and Customer-Funded Upgrades

Changes to the transmission system are incorporated into the RTEP base case based on the process drivers outlined in section 1.4.1 above in the form of three different types of upgrades or projects: 1) baseline upgrades (see sections 1.4.1.1 – 1.4.1.4); 2) Supplemental Projects (see sections 1.4.1.5); and 3) Customer-Funded Upgrades (see sections 1.4.1.6).

During the course of reviewing any upgrade or project, PJM will work with stakeholders to identify any upgrades or projects, or portions thereof that interact electrically. By doing so, PJM is able to determine the proper classification of a project based on one or more types of drivers, as well as develop the more efficient or cost-effective solutions.

1.4.2.1 When a Need is identified in the Attachment M-3 Process that requires development of a Supplemental Project (not yet included in RTEP base case)

During a review of the RTEP analysis, it may become apparent that a supplemental need identified in the Attachment M-3 Process may interact with an identified violation, system condition, economic constraint, or public policy requirement posted on the PJM website. In this case, PJM will provide notice of the potential interaction associated with the posted system

condition by posting the newly available information to the PJM website and provide notification to stakeholders. In addition, PJM may determine whether to lengthen an open proposal window in order to permit project proposers additional time to consider the availability of new or changed information. PJM can consider proposals, including proposals in its open proposal window that more efficiently and cost-effectively address both the identified baseline need(s) and any related needs identified in the Attachment M-3 Process.

1.4.2.2 When a Supplemental Project is submitted for inclusion in the Local Plan (not yet included in RTEP case)

During a review of the RTEP analysis, including input from stakeholders, it may become apparent that a Supplemental Project submitted for inclusion in the Local Plan, but not yet included in the RTEP base case, may interact with an identified violation, system condition, economic constraint, or public policy requirement posted on the PJM website. In this case, PJM will provide notice of the potential interaction associated with the posted system condition included in the PJM open proposal window. In addition, PJM may determine whether to lengthen the open proposal window in order to permit project proposers additional time to consider the availability of new or changed information regarding the facilities associated with the open proposal window, including any related needs identified in the Attachment M-3 Process.

In the development of the RTEP, PJM shall examine whether a possible baseline upgrade would more efficiently and cost-effectively address the identified regional need, as well as a supplemental need addressed by a proposed Supplemental Project.

If PJM identifies that a possible baseline upgrade would more efficiently and cost-effectively address the identified regional need, as well as a supplemental need, PJM will discuss with the relevant Transmission Owner and other stakeholders at the next appropriate Subregional RTEP or TEAC meeting. PJM shall submit the proposed baseline upgrade to the PJM Board for inclusion in the RTEP.

The Transmission Owner shall determine whether the baseline upgrade meets the supplemental need addressed by the proposed Supplemental Project and, if so, the Transmission Owner will withdraw the project from inclusion in the Local Plan. The Transmission Owner will inform PJM and the stakeholders at the next appropriate Subregional RTEP or TEAC meeting that the Supplemental Project will not be submitted for inclusion in the Local Plan.

If the Transmission Owner subsequently determines that the supplemental need is not met, the TO at the next appropriate Subregional RTEP or TEAC meeting will: (1) provide documentation to PJM and the stakeholders on the rationale supporting its determination; and, (2) inform PJM and the stakeholders that the Supplemental Project will be submitted for inclusion in the Local Plan. Accordingly, PJM will include the proposed Supplemental Project in the next RTEP base case. After discussion with the relevant Transmission Owner, PJM will notify the relevant regulatory siting authority, if applicable, when a Supplemental Project is being reviewed that

PJM has identified a baseline violation for which the baseline solution may impact the supplemental need for the Supplemental Project.

Any disputes arising under Attachment M-3, including any substantive and procedural disputes arising from the transmission planning process, may be resolved in accordance with the dispute resolution procedures in Schedule 5 of the Operating Agreement.

1.4.2.3 When a baseline upgrade is included in RTEP base case (in a prior RTEP cycle) and a Supplemental Project or Customer-Funded Upgrade is identified which interacts with the need for the baseline upgrade

PJM will review the needs for each of the upgrades or projects and review these needs with the stakeholders. This review will include, but is not limited to, the determination of how each upgrade or project may or may not satisfy the needs of one or more of the processes, and a review of the proposed schedules for the upgrades or projects and the system timing needs in order to inform these discussions.

Following a review of the applicable information, PJM shall determine the steps to be taken in order to preserve baseline reliability while also accommodating other system needs for the M-3 and the Cycle and Upgrade Request evaluation processes. Stakeholders will be provided an opportunity to discuss PJM's findings prior to PJM making a decision as to how PJM will proceed.

The Transmission Owners provide status updates in accordance with Section 6 of Manual 14C. Such status updates should include an indication of any relevant regulatory siting authority approval necessary for the project and the status of such approval. If at any time, PJM identifies a baseline need where a possible baseline upgrade would more efficiently and cost-effectively address the baseline need, as well as the identified needs for any proposed Supplemental Project, PJM will notify the relevant regulatory siting authority where the Supplemental Project is being reviewed that PJM has identified a baseline violation for which the baseline upgrade may impact the supplemental need for the Supplemental Project.

1.4.2.4 Incorporation of EOL Needs into the RTEP

The Transmission Owners shall prepare and provide to PJM, on an annual basis, a Candidate EOL Needs List. This The candidate EOL list shall be comprised of a Transmission Owners its non-public confidential, non-binding projection of up to 5 years of EOL Needs that it has identified under the Transmission Owner's processes for identification of EOL Needs. The methodology used by the Transmission Owner to determine inclusion in this EOL list shall be presented to stakeholders annually, and will generally be provided during the assumptions meeting as part of the M-3 process as outlined in Section 1.1. PJM shall identify any potential substantial electrical overlap between an identified PJM planning criteria need identified during the current PJM planning cycle, under the RTEP process and a projected EOL need facility on a Transmission Owner's Candidate EOL Needs List that could potentially be addressed by a single solution., PJM will consult with the relevant Transmission Owner to confirm the projected

EOL need still exists. If Transmission Owner confirms the projected EOL need still exists, PJM would post both the PJM planning criteria need and projected EOL need facility as required pursuant to Schedule 6 open window process, noting the overlap on the list of violations posted for the proposal window.

1.4.3 Addition and Removal of System Projects or Upgrades from the RTEP Base Cases

The development of an RTEP requires PJM to maintain a base case that includes all previously-identified system reinforcements regardless of the driver to be used in its analysis of system needs.

Each year, PJM must lock down the assumptions included in the annual RTEP base case in order to move forward with its analysis. PJM will employ the following guidelines regarding when to include the following types of projects or upgrades in the annual RTEP base case:

1. Baseline upgrades will be included in the next RTEP base case once the baseline upgrade is approved by the PJM Board in accordance with Schedule 6 of the Operating Agreement
2. Customer-Funded Upgrades will be included in the next RTEP base case once: (1) the Customer-Funded Upgrades are included in an executed Generation Interconnection Agreement, Upgrade Construction Service Agreement, Wholesale Market Participation Agreement or Transmission Services Agreement; or, (2) if the completion of the RTEP requires inclusion of New Service Requests that have met all Decision Point II requirements in order to meet the new load requirements resulting from normal forecasted load growth.
3. Supplemental Projects will be included in the next RTEP base case following inclusion of the Supplemental Project in the Local Plan, consistent with section 1.4.2.2 above.
4. A Customer-Funded Upgrade may be removed from the RTEP base case upon termination or cancellation of an executed service agreement provided such upgrade is not required by another New Service Request in the same Cycle.

5. If a relevant regulatory siting authority denies a siting application for a project included in the RTEP or refuses to allow the project to move forward under the conditions specified in such order and such order is a final regulatory order exhausting all regulatory process, the following guidance is provided:
    a. The entity receiving a final regulatory order from the relevant regulatory siting authority shall promptly notify and provide PJM with a copy of such order;
        i. Upon receipt of such notice, PJM will review the impacts associated with removing the project from the RTEP or continuing to include such project in light of such final regulatory order (see section 1.4.2 above for guidance relative to the review process);
    b. PJM shall present to the TEAC the results of PJM's re-evaluation for review and comment.
    c. A project denied siting authority in a final regulatory order by the relevant regulatory siting authority will generally be removed from the RTEP base case as determined by PJM after discussion with the relevant Transmission Owner(s) or Designated Entity and vetting with stakeholders at the TEAC. A project will generally not remain in the RTEP base case during the duration of a court appellate action. Decisions to remove a baseline upgrade from the RTEP base case will be submitted to the PJM Board and decisions to remove a Supplemental Project from the RTEP base case will be provided to the applicable Transmission Owner. In those circumstances in which PJM determines the need to deviate from this guidance, PJM will discuss such decisions with the TEAC.

1.5 Planning Criteria

1.5.1 Reliability Planning

PJM and/or Transmission Owners' planning information, including models, criteria and assumptions, provided pursuant to Operating Agreement, Schedule 6 or OATT, Attachment M-3 must be adequate to allow stakeholders to replicate the results of planning studies.

Stakeholders have the opportunity at a national level through the participatory standards development process of the North American Electric Reliability Corporation (NERC) to influence the industry planning criteria that form the basis of PJM's planning process (found at http://www.nerc.com/Pages/default.aspx.) NERC regional criteria development, applicable to PJM, is also open to stakeholder input through the open and participatory process of ReliabilityFirst Corporation (found at https://rfirst.org/ProgramAreas/Standards/.)

Additionally, regional and Transmission Owner planning criteria that go beyond and complement the NERC Reliability Standards can be created and incorporated into PJM planning through participation in PJM's Planning Committee and other related stakeholder processes (please refer to http://pjm.com/committees-and-groups/committees.aspx.) In this manner, PJM, as the independent planning authority, avails stakeholders full opportunity to participate in the planning

process from assumptions setting to the final plan. The PJM annual regional plan is based on the effective criteria in place at the time of the analyses, including applicable standards and criteria of the NERC and the applicable regional reliability entity[1], the various Nuclear Plant Licensees' Final Safety Analysis Report grid requirements and the PJM and Transmission Owner Reliability Planning Criteria (Attachment D). Section 2 details the specific criteria applicable to each transmission planning process study phase. Criteria are comparably applicable to all similarly situated Native Load Customers and other Transmission Customers.

1.5.2 Market Efficiency Planning

Market efficiency planning is an evaluation process that results in facilities planned to achieve economic efficiencies rather than an analysis that produces violations measured against criteria. This process compares alternative plans' cost effectiveness in improving transmission efficiency and produces RTEP recommendations from this process. The metrics of economic inefficiency include historic and projected congestion. The measures of historic congestion are gross congestion, unhedgeable congestion, and pro-ration of auction revenue rights. The measure of projected congestion is based on a market analysis of future system conditions performed with a commercially available security constrained, economic dispatch market analysis tool. This market analysis results in future projections of the congestion and its binding constraint drivers. These congestion measures are posted and available to stakeholders by binding constraint and form the basis for PJM and stakeholder development of remedies. Transmission plans from the reliability analysis or a new plan presented that economically relieves historical or projected congestion are candidates for market efficiency solutions. The successful candidates will be those facilities that pass PJM's threshold test and bright line economic efficiency test. This test specifies that a proposed solution's savings must exceed its projected revenue requirements, on a 15 year present worth basis, by at least 25% (the threshold cost/benefit test). Each of this process' elements, its underlying assumptions and its methods is described in more detail in the accompanying sections of this manual 14B and in Attachment E.

1.5.3 FERC Form No. 715 Planning

The Transmission Owner's local planning criteria may be included in its FERC Form No. 715 filing. These documents may include criteria governing the planning of upgrades to the transmission system, which is in addition to the PJM Planning criteria and may include information specific to a Transmission Owner's asset management activities.

---

1 The Reliability*First* Regional Reliability Corporation (RRC) for the PJM Mid-Atlantic and Western Regions (which replaced the former ECAR, MAAC and MAIN RRCs on January 1, 2006) and the Virginia-Carolinas (VACAR) Area Reliability subregion of the SERC Reliability Corporation for PJM Southern Region.

1.5.4 Supplemental Project Planning

The criteria driving the need for Supplemental Projects (which could include criteria required to address end of useful life of existing transmission facilities, and which, in accordance with good utility practice, is not determined by the facility's service life for accounting or depreciation purposes) are provided by each Transmission Owner consistent with the OATT Attachment M-3 process.

Section 2: Regional Transmission Expansion Plan Process

In this section you will find an overview of the PJM Region transmission planning process covering the following areas:

- Components of PJM's 15-Year planning
- The need and drivers for a regional transmission expansion plan
- Reliability planning overview
- Specific components of reliability planning and the Stakeholder process
- Interconnection request drivers of RTEP
- Cost responsibility for reliability related upgrades
- Market efficiency planning review
- Specific components of market efficiency planning and the Stakeholder process.
- Operational performance driven planning
- Specific components of operational performance driven planning

2.1 Transmission Planning = Reliability Planning + Market Efficiency+ FERC Form No. 715 + Public Policy + Supplemental Project Planning

Effective with the 2006 RTEP, PJM, after stakeholder review and input, expanded its RTEP Process to extend the horizon for consideration of expansion or enhancement projects to fifteen years. This enables planning to anticipate longer lead-time transmission needs on a timely basis.

Fundamentally, the Baseline reliability analysis underlies all planning analyses and recommendations. On this foundation, PJM's annual 15-year planning review now yields a regional plan that encompasses the following:

1. Baseline reliability upgrades, discussed in this Section 2;
2. Operational Performance issue driven upgrades, discussed in Section 2;
3. Market efficiency driven upgrades, discussed in this Section 2;
4. FERC Form No. 715 projects, discussed in Section 2;
5. Public Policy Requirements based elements via State Agreement Approach;
6. Supplemental Projects by a Transmission Owner, addressed via OATT, Attachment M-3, which could include projects addressing the end of useful life of existing facilities, which, as determined in accordance with good utility practice, is not determined by the facility's service life for accounting or depreciation purposes.
7. Avoidance of system enhancements that do not meet critical substation planning analysis objectives discussed in Section 2.

2.1.1 Multi-Driver Approach

In the event that a proposed project is driven by more than one of the above stated drivers, PJM can develop a Multi-Driver Approach Project, as defined in Schedule 6 of PJM's Operating Agreement by identifying a more efficient or cost effective solution that follows one of the following methods:

Proportional Multi-Driver Method: Combining separate solutions that address reliability, economics and/or public policy into a single transmission enhancement or expansion that incorporates separate drivers into one Multi-Driver Project.

Incremental Multi-Driver Method: Expanding or enhancing a proposed single-driver solution to include one or more additional component(s) to address a combination of reliability, economic and/or public policy drivers.

2.1.1.1 Principles and Guidelines for New Service Requests as an input to Multi-Driver Approach

Customer-Funded upgrades, as identified in PJM Manual 14H may be incorporated into the Multi-Driver Approach Project per the Regional Transmission Expansion Plan. Project Developers, other than those proposing Merchant Network Upgrades, have the option, but not obligation to participate in a Multi-Driver Approach Project, at the direction of PJM. The following principles and guidelines must be adhered to for a Project Developer wishing to participate in a Multi-Driver Approach Project:

1. The Multi-Driver Approach Project must be more cost effective as a whole, than the sum of the individual projects
2. Project Developer has the option, but not the obligation to participate in a Multi-Driver Approach Project. The Project Developer must execute an agreement committing to be financially responsible for its portion of the Multi-Driver Approach Project, the cost of which shall not exceed the cost of the incremental upgrade required as part of the New Service Request, unless agreed to by the sponsoring Project Developer(s).
3. Project Developer's participation in the Multi-Driver Approach Project shall not impact the Project Developer's Cycle position.
4. Commencement of service for the Project Developer's Customer Facilities may be impacted by the in-service date of the Multi-Driver Approach Project.
5. The following cost allocation rules will apply to Multi-Driver Approach Projects: Schedule 12 of the PJM Tariff for the component of the upgrade to be funded for reliability violations or operational performance, economic constraints and/or Public Policy Requirements; and Part VIII of the PJM Tariff for the Project Developer's portion of the Multi-Driver Approach Project.

2.1.2 Reliability Planning

Exhibit 1 shows the 24-month Reliability planning process used for the 15-year RTEP horizon. This 24-month planning process integrates the upgrades noted above with information transparency, stakeholder input and review and PJM Board of Manager approvals. Activities shown on this diagram and their timing are for illustrative purposes. The actual timeline may vary to some degree to be responsive to the RTEP and stakeholder needs.

The 24-month planning process is made up of overlapping 18-month planning cycles (Refer to Exhibit 1) to identify and develop shorter lead-time transmission upgrades and one 24-month planning cycle to provide sufficient time for the identification and development of longer lead-time transmission upgrades that may be required to satisfy planning criteria. Consistent with the requirements of the NERC TPL Reliability Standards the 24-month planning process includes both near-term (years one through five) and long-term (years six through fifteen) assessments of the transmission system as described below.

The first step in the process is to develop the set of assumptions that will be used for the subsequent analyses. These assumptions are vetted with stakeholders at Transmission Expansion Advisory Committee and Subregional RTEP Committees meetings. A series of power-flow base cases are then developed based on the assumptions. The yearly series of cases include the latest information and assumptions available related to load, resources and transmission topology. A new 5-year base case is developed for near-term baseline reliability analysis. Base cases for retool analyses of years closer than 5-years are developed as required. Retool analysis is used to review previously established assumptions, later in the planning cycle, as those assumptions may have changed.

In addition to these near-term base cases additional power-flow base cases are developed for long-term planning. These long-term cases are used to evaluate the need for more significant projects requiring a longer time to develop. These longer lead time projects generally provide a more regional benefit. The long-term base case developed at the start of each 24-month planning cycle is based on the system conditions that are expected to exist in year eight. As noted in Exhibit 1, this 8-year out base case is updated and retooled at the start of the second year of the 24-month planning cycle (i.e. at that point a 7-year out base case), with additional criteria analysis being run to validate the findings from the analysis that was conducted during the first year of the 24-month planning cycle.

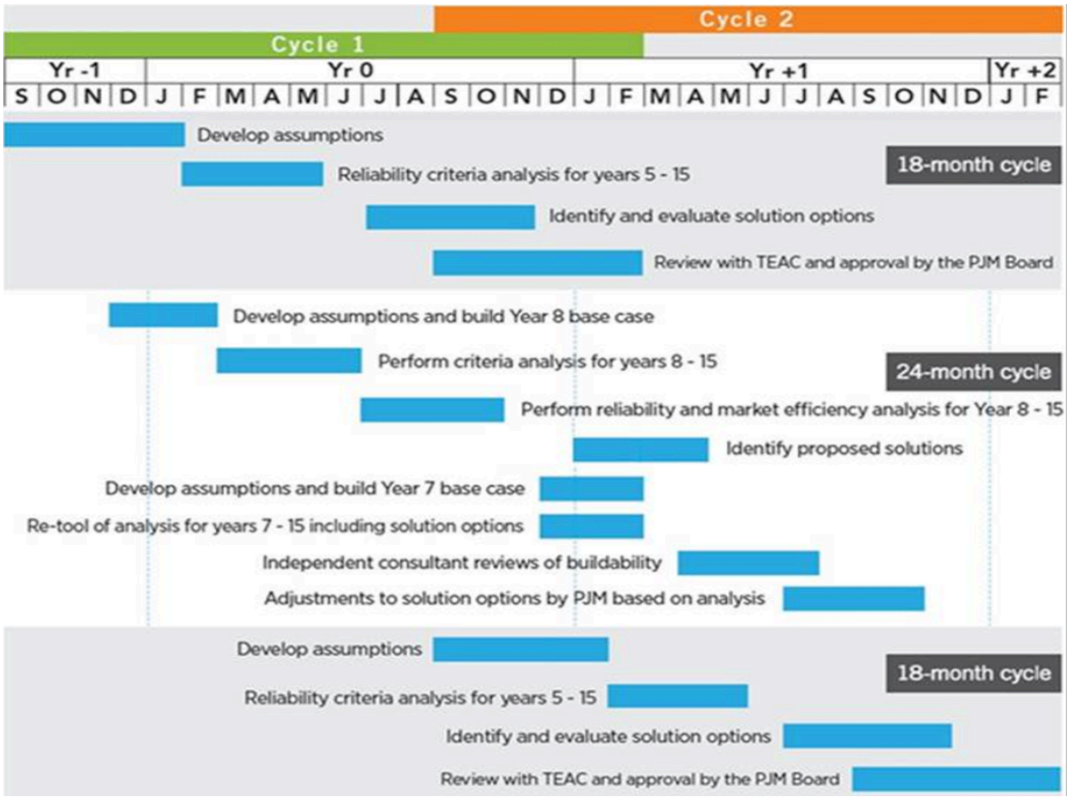


Exhibit 1: 24-Month Reliability Planning Cycle

The scope of the near-term baseline analysis that is completed as part of each 12-month planning cycle includes an exhaustive review of applicable reliability planning criteria on all BES facilities as described in section 2.3 of this manual. As noted above, PJM typically performs this near-term analysis on a 5-year out base case. Retool analyses of previous near-term assessments are also completed, as required. Any identified criteria violations are reviewed with stakeholders throughout the planning process. Ultimately, solutions to address the criteria violations are developed, reviewed with the TEAC and/or Sub-regional RTEP Committee as applicable, and submitted to the PJM Board of Managers for approval. Through this planning process, a baseline system without any criteria violations is developed for the near-term (i.e., 5-year baseline). This baseline system, without any criteria violations, is then used for subsequent Cycle studies.

Long-term planning is also completed as part of the development of the RTEP to identify solutions to planning criteria violations that require longer lead times to implement. As part of the 24-month planning cycle PJM initially develops an 8-year out base case that is used to evaluate planning criteria for the long-term planning horizon. Long term criteria analysis is completed on this base case during the first year of the 24-month cycle. A combination of a full

AC power flow solution and linear analysis, as described in this manual, is used to determine the loading on facilities for years 8 through 15. Violations and proposed solutions to address them are developed by stakeholders and PJM staff during the first year of the 24-month planning cycle. As shown in Exhibit 2, during the second year of the 24-month planning cycle, the base case used for the long-term analysis during the first year (i.e., now year 7) is updated to reflect the latest assumptions about load, generation, DR, EE, and transmission topology. Long term criteria analysis is completed on this base case during the second year of the 24-month cycle. A combination of a full AC power flow solution and linear analysis, as described in this manual, is again used to determine the loading on facilities for years 7 through 15. Potential violations identified during the first year are validated and the proposed solutions to address those violations are refined during the second year of the 24–month planning cycle. An independent consultant may be used to develop an independent cost estimate and evaluate the constructability of proposed solutions. Results from these long-term analyses, including potential violations and their solutions, are reviewed with the TEAC throughout the 24-month planning process. Ultimately, any required long-lead time solutions that are identified through this planning process are presented to the PJM Board of Managers for approval.

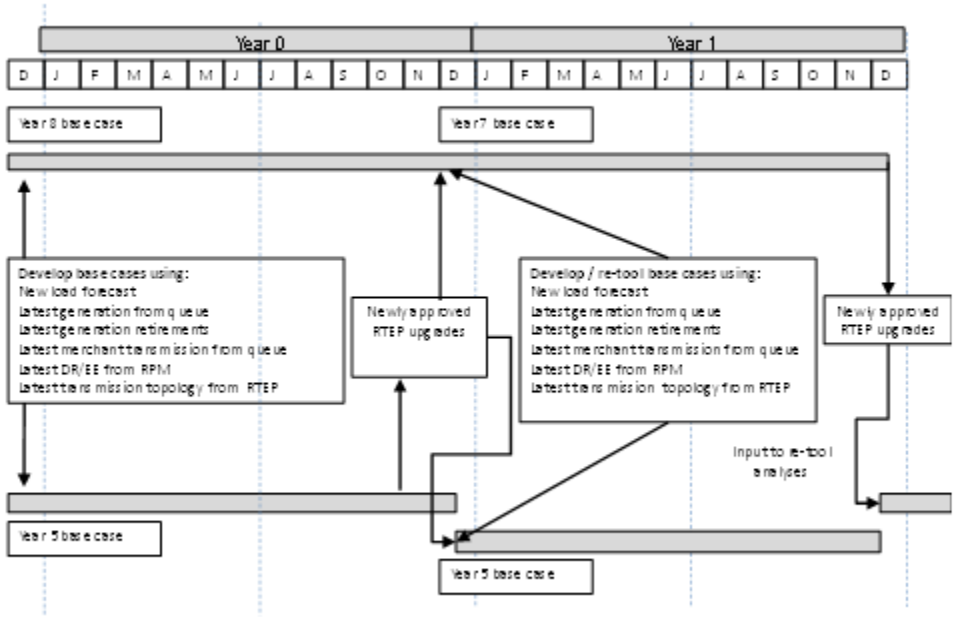


Exhibit 2: Base Case Development

2.1.3 Market Efficiency Planning

Exhibit 3 shows the 24-month Market Efficiency process used for the 15-year RTEP horizon. Activities shown on this diagram and their timing are for illustrative purposes. The actual timeline may vary to some degree to be responsive to the RTEP and stakeholder needs.

The 24-month Market Efficiency process is made up of two similar 12-month cycles to identify approved RTEP projects that may be accelerated or modified and one 24-month planning cycle to provide sufficient time for the identification and development of longer lead-time transmission upgrades.

The first step in the Market Efficiency process is to develop the set of assumptions that will be used for the subsequent analyses. These assumptions are vetted with stakeholders at the Transmission Expansion Advisory Committee meetings.

The scope of the near-term Market Efficiency analysis that is completed as part of each 12-month planning cycle includes a review of the congestion in year 1 and year 5 and existing approved RTEP projects. This review will identify approved RTEP projects that may be accelerated or modified and meet the Market Efficiency Benefit/Cost criteria as explained in accompanying sections of this Manual 14B.

Long-term Market Efficiency planning is also completed as part of the development of the RTEP to identify solutions that require longer lead times to implement. As part of the 24-month Market Efficiency planning cycle, PJM initially develops a base case for years 1, 5, 8, 11, and 15 that are used to evaluate congestion for the long-term planning horizon. A higher level base case is developed for year 15 and may require a less detailed model of the transmission system below the 500 kV level as explained in section 2.6.5 of this manual. Proposed solutions to address Market Efficiency projected congestion are developed by stakeholders and PJM staff during the first year of the 24-month planning cycle. As shown in Exhibit 3, during the second year of the 24-month cycle, the base cases used for the long-term analysis during the first year (i.e., now year 0, 4, 7, 10, and 14) will be updated, as appropriate, to reflect the latest assumptions regarding load, generation, demand response, transmission topology, or other input assumptions.

Congestion issues identified during the first year are validated and the proposed solutions are refined during the second year of the 24–month cycle. An independent consultant may be used to develop a cost estimate and evaluate the constructability of proposed solutions. Results from these long-term analyses are reviewed with the Transmission Expansion Advisory Committee throughout the 24-month planning process, and, ultimately, presented to the PJM Board of Managers for approval.

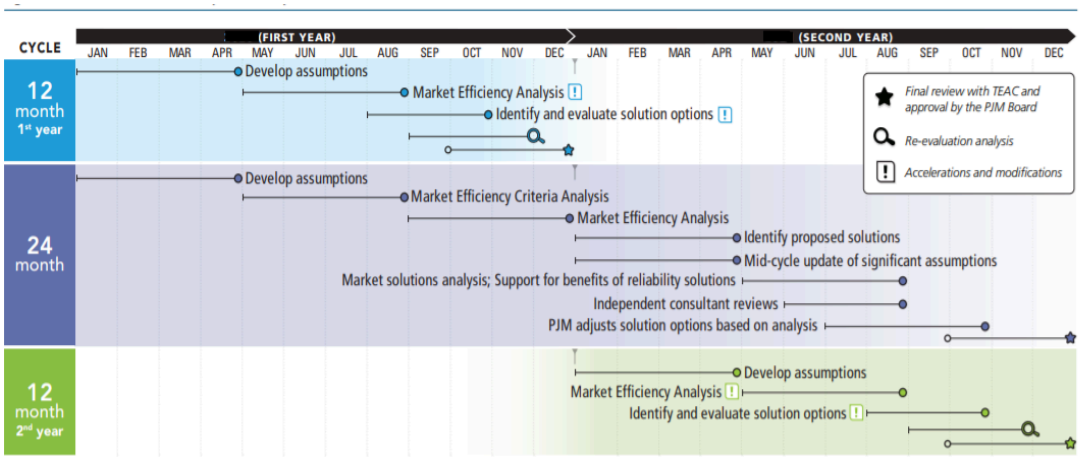


Exhibit 3: 24-Month Market Efficiency Cycle

2.2 The RTEP Process Drivers

The continuing evolution and growth of PJM's robust and competitive regional markets rests on a foundation of bulk power system reliability, ensuring PJM's ongoing ability to meet control area load-serving obligations. It also includes a commitment to enhance the robustness and competitiveness of Energy and Capacity markets by incorporating analysis and development of market efficiency projects. Schedule 6 of the PJM Operating Agreement describes the PJM RTEP process, governing the means by which PJM coordinates the preparation of a plan for the enhancement and expansion of the Transmission Facilities – on a reliable and environmentally sensitive basis and in full consideration of available economic and market efficiency factors and alternatives - in order to meet the demands for firm transmission service in the PJM region. PJM's FERC-approved RTEP process preserves this foundation through independent analysis and recommendation, supported by broad stakeholder input and approval by an independent RTO Board in order to produce a single RTEP.

The PJM Region transmission planning process is driven by a number of planning perspectives and inputs, including the following:

- ReliabilityFirst Regional Reliability Corporation[2] (RFC) Reliability Assessment – forward-looking assessments performed to assure compliance with NERC and applicable regional

2 Reliability*First*, a new regional reliability corporation under the North American Electric Reliability Corporation (NERC), replaced three existing PJM-related reliability councils (ECAR, MAAC and MAIN) on January 1, 2006.

reliability corporation (ReliabilityFirst or SERC Reliability Corporation) reliability standards, as appropriate.

- SERC Reliability Corporation (SERC) Reliability Assessment
- PJM Annual Report on Operations – an assessment of the previous year's operational performance to assure that any bulk power system operational conditions which have emerged, e.g., congestion, are adequately considered going forward.
- PJM Load Serving Entity (LSE) capacity plans
- Generator and Transmission Interconnection Requests – submitted by the developers of new generating sources and new Merchant Transmission Facilities, these requests seek interconnection in the PJM Region (or seek needed enhancements as the result of increases in existing generating resources.)
- Transmission Owner and other stakeholder transmission development plans
- Interregional transmission development plans – the transmission expansion plans of those power systems adjoining PJM, and in some cases, beyond.
- Long-term Firm Transmission Service Requests
- Activities under the PJM committee structure especially, the Planning Committee (PC), the Transmission Expansion Advisory Committee (TEAC), the Subregional RTEP Committee, and local groups facilitated by PJM within the TEAC established processes (see section 1 "TEAC, Subregional RTEP Committee, and related planning activities".)
- PJM Development of Economic Transmission Enhancements based on Economic and Market Efficiency factors
- Operational performance assessments and reviews such as the aging Infrastructure Initiative – a Probabilistic Risk Assessment of equipment that poses significant risk to the Transmission System.

The cumulative effect of these drivers is analyzed through the PJM Region transmission planning process to develop a single RTEP which recommends specific transmission facility enhancements and expansion on a reliable and environmentally sensitive basis and in full consideration of economic and market efficiency analyses. See Attachment B for details of the RTEP – Scope and Procedure.

Note:
The most recent version of the PJM RTEP is available PJM Web site at http://www.pjm.com/planning/rtep-upgrades-status.aspx.

These analyses are conducted on a continual basis, reflecting specific new customer needs as they are introduced, but also readjusting as the needs of Transmission Customers and Developers change. One such RTEP baseline regional plan will be developed and approved each year.

Note:

Generation deactivations, depending on the date of the announced retirement to PJM, have the potential to impact study results for any New Service Request that does not have an executed final agreement. Generation retirements that are announced to PJM by the Application Deadline of a Cycle will be turned offline in the base case model created for that particular Cycle and available to be turned on to contribute to but not back off flowgate loadings per the PJM Generator Deliverability Test procedures. Per Tariff Part VIII, Subpart E, Section 426, the unit will remain offline in the model until the CIRs expire (if not claimed by a New Service Request), one year after their actual deactivation date. If the CIRs do expire, the unit will be removed from the model.

In this way, the plan continually represents a reliable means to meet the power system requirements of the various Transmission Customers and Project Developers in a fully integrated fashion, at the same time preserving the rights of all parties with respect to the Transmission System. The assurance of a reliable Transmission System and the protection of the Transmission Customer/Developer rights with respect to that system coupled with the timely provision of information to stakeholders are the foundation principles of the PJM transmission planning process.

The PJM Region transmission planning process also establishes the cost responsibility for the following types of facility enhancements as defined in the PJM Tariff:

- Attachment Facilities
- Direct Assignment Facilities
- Network Upgrades (Direct and Non-direct)
- Distribution Upgrades
- Merchant Network Upgrades

Each RTEP encompasses a range of proposed power system enhancements: circuit breaker replacements to accommodate increased current interrupting duty cycles; new capacitors to increase reactive power support; new lines, line reconductoring and new transformers to accommodate increased power flows; and, other circuit reconfigurations to accommodate power system changes as revealed by the drivers discussed above.

Requests for interconnection of new generators or transmission facilities, while not the sole drivers of the PJM Region transmission planning process, are a key component of the RTEP. Analyzing these requests has required adoption of an approach that establishes baseline system improvements driven by known inputs, followed by separate Cycle-defined, cluster-based impact study analyses. Overall, PJM‘s RTEP process – under a FERC-approved RTO model – encompasses independent analysis, recommendation and approval to ensure that facility enhancements and cost responsibilities can be identified in a fair and non-discriminatory

manner, free of any market sector's influence. All PJM market participants can be assured that the proposed RTEP was created on a level playing field.

2.3 RTEP Reliability Planning

2.3.1 Establishing a Baseline

In order to establish a reference point for the annual development of the RTEP reliability analyses a 'baseline' analysis of system adequacy and security is necessary. The purpose of this analysis is threefold:

- To identify areas where the system, as planned, is not in compliance with applicable NERC and the applicable regional reliability council (ReliabilityFirst or SERC) standards, Nuclear Plant Licensee requirements and PJM reliability standards including equipment replacement and/or upgrade requirements under PJM's Aging Infrastructure Initiative. The baseline system is analyzed using the same criteria and analysis methods that are used for assessing the impact of proposed new interconnection projects. This ensures that the need for system enhancements due to baseline system requirements and those enhancements due to new projects are determined in a consistent and equitable manner.
- To develop and recommend facility enhancement plans, including cost estimates and estimated in-service dates, to bring those areas into compliance.
- To establish the baseline facilities and costs for system reliability. This forms the baseline for determining facilities and expansion costs for interconnections to the Transmission System that cause the need for facilities beyond those required for system reliability.

The system as planned to accommodate forecast demand, committed resources, and commitments for firm transmission service for a specified time frame is tested for compliance with NERC and the applicable regional reliability council (ReliabilityFirst or SERC) standards, Nuclear Plant Licensee requirements, PJM Reliability Standards and PJM design standards. Areas not in compliance with the standards are identified and enhancement plans to achieve compliance are developed.

The 'baseline' analysis and the resulting expansion plans serve as the base system for conducting Phase I System Impact Studies for all proposed generation and/or merchant transmission facility interconnection projects and subsequent System Impact Studies.

2.3.2 Baseline Reliability Analysis

PJM's most fundamental responsibility is to plan and operate a safe and reliable Transmission System that serves all long term firm transmission uses on a comparable and not unduly discriminatory basis. This responsibility is addressed by PJM RTEP reliability planning. Reliability planning is a series of detailed analyses that ensure reliability under the most stringent of the applicable NERC, PJM or local criteria. To accomplish this each year, the RTEP cycle extends and updates the transmission expansion plan with a 15 year review. This cycle entails several steps. The following sections describe each step's assumptions, process and

criteria. Attachments A through F of this manual add essential details of various aspects of the reliability planning process.

Reliability planning involves a near-term and a longer term review. The near term analysis is applicable for the current year through the current year plus 5. The longer term view is applicable for the current year plus 6 through plus 15. Each review entails multiple analysis steps subject to the specific criteria that depend on the specific facilities and the type of analysis being performed.

The analysis is initiated following the completion of case builds and concludes with review by the TEAC and approval by the PJM Board (TEAC and the PJM Board are appraised regularly throughout the process and partial reviews and approvals of the plan may occur throughout the year.) The TEAC, Subregional RTEP and PJM Planning Committee roles in the development of the reliability portion of the RTEP are described in Schedule 6 of the PJM Operating Agreement.

2.3.3 Near-Term Reliability Review

The near-term reliability review (current year plus 5) provides reinforcement for criteria violations that are revealed by applicable contingency analysis. Limits used in the analysis are established consistent with the requirements of NERC standards FAC-010 and FAC-014. The methodology used to determine system operating limits is included in Attachment-F of this manual. System conditions revealed as near violations will be monitored and remedied as needed in the following year near-term analysis. Violations that occur in many deliverability areas or severe violations in any one area will be referred to the long term analysis for added study of possible more robust system enhancement. PJM annually conducts this detailed review of the current year plus 5. The annual review shall include system peak load for either year one or year two, and for year five.

For the annual evaluation of the near-term, sensitivity cases shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the system within a range of credible conditions that demonstrate a measurable change in system response.

- Real and reactive forecasted load
- Expected transfers
- Expected in service dates of new or modified transmission facilities
- Reactive resource capability
- Generation additions, retirements, or other dispatch scenarios
- Controllable loads and demand side management

Duration or timing of known transmission outages

Each year of the period through the current year plus 4 (“in-close” years) has been the subject of previous years’ detailed analyses. In addition, for each of these “in-close” years, PJM updates and issues addendum to address changes as necessary throughout the year. For example planned generation modifications or changes in transmission topology can trigger restudy and the issuance of a baseline addendum. This is referred to as a “retool” study. (For example generators that drop from the Cycle cause restudy and an addendum to be issued for affected baseline analyses.) Also each year during the establishment of the assumptions for the new annual baseline analysis, current updated views of load, transmission topology, installed generation, and generation and transmission maintenance are assessed for the “in-close” range of years to validate the continued applicability of each of the “in-close” baseline analyses and resulting upgrades (including any addendum.) Adjustments in the “in-close” analyses are performed as deemed necessary by PJM. PJM, therefore, annually verifies the continued need for or modification of past recommended upgrades through its retool studies, reassessment of current conditions and any needed adjustments to analyses. All criteria thermal and voltage violations resulting from the near term analyses are produced using solved AC power flow solutions. Initial massive contingency screening may use DC power flow solution techniques.

There are seven steps in an annual near-term reliability review. They are:

- Develop a Reference System Power Flow Case
- Baseline Thermal
- Baseline Voltage
- Load Deliverability - Thermal
- Load Deliverability - Voltage
- Generator Deliverability - Thermal
- Baseline Stability

These reliability related steps are followed by a scenario analysis that ensures the robustness of the plan by looking at impacts of variations in key parameters selected by PJM. Each of these steps is described in more detail in the following material.

2.3.4 Reference System Power Flow Case

The reference power flow case and the analysis techniques comprise the full set of analysis assumptions and parameters for reliability analysis. Each case is developed from the most recent set of Eastern Reliability Assessment Group system models. PJM transmission planning revises this model as needed to incorporate all of the current system parameters and assumptions. These assumptions include current loads, installed generating capacity, transmission and generation maintenance, system topology, incorporation of the most recently finalized Local Plans and firm transactions. These assumptions will be provided to and reviewed by the Subregional RTEP Committee. The subregional modeling review and modeling assumptions meeting provides the opportunity for stakeholders to review and provide input to the development of the reference power system models used to perform the reliability analyses.

The results of any locational capacity market auction(s) will be used to help determine the amount and location of generation or demand side resources to be included in the reliability modeling. Generation or demand side resources that are cleared in any locational capacity market auction will be included in the reliability modeling, and generation or demand side resources that either do not bid or do not clear in any locational capacity market auction will not be included in the reliability modeling. All such modeling described here will comport with the capacity construct provisions approved by the FERC.

Subsequent to the subregional stakeholder modeling reviews facilitated by PJM, PJM will develop the final set of reliability assumptions to be presented to TEAC for review and comment, after which PJM will finalize the reliability review reference power flow. This model is expected to be available in early January of each year to interested stakeholders, subject to applicable confidentiality and CEII requirements, to facilitate their review of the results of the reliability modeling analyses.

2.3.5 Contingency Definitions

Contingency definitions used in RTEP analysis are the same as applicable NERC TPL contingency definitions. In addition to studying all contingency types listed in TPL-001 Table 1, PJM also studies bus tie breaker openings without a fault as a single contingency. Where the physical design of connections or breaker arrangements results in the outage of more than the faulted equipment when a fault is cleared, the additional facilities are also taken out of service in the contingency definition. For example, if a transformer is tapped off a line without a breaker, both the line and transformer are removed from service as a single contingency event.

Contingency definitions for double circuit tower line outages shall include any two adjacent (vertically or horizontally) circuits on a common structure, but shall exclude circuits that share a common structure for one mile or less. The loss of more than two circuits on a common structure constitutes a NERC extreme event.

PJM will coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that contingencies on adjacent systems which may impact their system are included in the contingency list.

2.3.6 Baseline Thermal Analysis

Baseline thermal analysis is a thorough analysis of the reference power flows for light load, summer and winter to ensure thermal adequacy based on normal (applicable to system normal conditions prior to contingencies) and emergency (applicable after the occurrence of a contingency) thermal ratings specific to the Transmission Owner facilities being examined. It is based on a 50/50 load forecast for the applicable period from the latest available PJM Load Forecast Report (50% probability that the actual load is higher or lower than the projected load.) It encompasses an exhaustive analysis of all single and common mode (NERC P0, P1, P2, P4, P5 and P7 events). Final results are supported with AC power flow solutions. Demand Response is not considered in the baseline analysis.

2.3.7 Baseline Voltage Analysis

Baseline voltage analysis parallels the thermal analysis. It uses the same power flow models for light load, summer and winter and examines voltage criteria for all the same NERC P0, P1, P2, P4, P5, and P7 set of single and common mode outage events.

Analysis will simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. Those devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors. PJM examines system performance for both a voltage drop criteria (where applicable) and a voltage magnitude criteria. The voltage drop is calculated as the decrease in bus voltage from the initial steady state power flow to the post-contingency power flow. The post-contingency power flow is solved with generators holding a local generator bus voltage to a pre-contingency level consistent with specific Transmission Owner specifications. In most instances this is the pre-contingency generator bus voltage. Additionally, all phase shifters, transformer taps, switched shunts, and DC lines are locked for the post-contingency solution. SVC's are allowed to regulate and fast switched capacitors are enabled.

The voltage magnitude criteria is examined for the same contingency set by allowing transformer taps, switched shunts and SVC's to regulate, locking phase shifters and allowing generators to hold steady state voltage criteria (generally an agreed upon voltage on the high voltage bus at the generator location.)

In all instances, specific Transmission Owner voltage criteria are observed. All violations are recorded and reported and tentative solutions will be developed. These study results will be presented to and reviewed with stakeholders.

Post-Contingency voltage analysis shall also include the impact of tripping generators where the simulated generator bus voltages or the high side of the generation step up (GSU) transformer are less than known or assumed minimum generator steady state of ride through voltage limitations. All violations will be reported and tentative solutions will be developed. The results of these studies will be reviewed through the TEAC.

2.3.8 NERC P3 and P6 "N-1-1" Analysis

Purpose

N-1-1 studies are conducted as part of the annual RTEP to determine if all monitored facilities can be operated:

- Within normal thermal and voltage limits after N-1 (single) contingency assuming re-dispatch and system adjustments, and
- Within the applicable emergency thermal ratings and voltage limits after an additional single contingency (N-1-1) condition.

All violations of the applicable thermal ratings are recorded and reported and tentative solutions will be developed. These study results will be presented to and reviewed with stakeholders.

Model

Annually, the N-1-1 study is conducted on a 50/50 non-diversified summer and winter peak case. The case building details are defined in Attachment C (C7 3.0 Step 1: Develop Base Case). Non-firm Merchant Transmission withdrawals can be removed. All BES facilities in PJM and ties to PJM will be monitored. In addition, non-BES facilities included in the real-time congestion management facility list will be examined on the light load case. Areas of the system that become radial post-contingency will be excluded from monitoring, with the following exceptions

- If the radial system contains greater than 300 MW of load, or
- Specific local TO Planning Criteria require that it be monitored.

Contingencies considered:

- All BES single contingencies as defined in NERC P3 and P6 as well as lower voltage facilities that are monitored by PJM Operations will be included in the assessment. Non-BES contingencies, defined by Transmission Owners, need to be included to check for greater than 300 MW load loss impacting numerous customers. Non-BES facilities that are included in the assessment will also have corresponding contingencies defined.

AC Solution Options in the PSS/E program:

- For the first single contingency (N-1 Condition) and to ensure the system remains within emergency thermal ratings
  - Transformer tap adjustment enabled
  - Switched shunt adjustment enabled
- After the first single contingency (N-1 Condition) and to return the system back within normal thermal ratings
  - Phase shifter adjustment enabled
  - System re-dispatched
  - Topology changes implemented
- For the second single contingency (N-1-1 Condition) – Voltage Drop Test (if applicable)
  - Transformer tap adjustment disabled
  - Phase shifters locked to control angle, not flow
  - Switched shunt adjustment disabled except for fast switched capacitors
  - Generators are set to regulate their terminal bus
  - SVC’s are allowed to regulate
  - Automatic shunt adjustment disabled

- For the second single contingency (N-1-1 Condition) – Thermal and Voltage Magnitude Test
  - Transformer tap adjustment enabled
  - Phase shifters locked to control angle, not flow
  - Switched shunt adjustment enabled
  - Automatic shunt adjustment enabled

PJM NERC P3 and P6 “N-1-1” Methodology

Thermal Test Methodology:

The PJM NERC P3 and P6 “N-1-1” Analysis will test the outage of every single contingency (N-1 condition)

The first step of the test is to ensure that post-contingency loadings of all facilities shall be within their emergency thermal ratings immediately following the first N-1 contingency

The second step of the test is to ensure that post contingency loadings of all facilities shall be within their normal thermal ratings after the first N-1 contingency and subsequent re-dispatch and system adjustments. Allowable system adjustments include generation dispatch, phase shifter adjustment, system reconfiguration and load throw-over.

The third step is to take the second N-1-1 contingency. Every second N-1-1 contingency is taken on every optimized N-1 scenario case to model the N-1-1 condition. After the second N-1-1 contingency, the thermal loading of any monitored facility that is above the applicable emergency thermal rating (long-term or short-term) is considered a reliability criteria violation and a mitigation plan will be needed.

Voltage Drop Test Methodology

The N-1-1 Voltage Drop Test procedure follows a similar method as the thermal test method, except all monitored facilities are monitored for the emergency voltage drop limit after the second contingency (N-1-1 condition.) The calculation of voltage drop is defined in section 2.3.7.

Voltage Magnitude Test

The N-1-1 Voltage Magnitude Test procedure follows a similar method as the thermal test method, except all monitored facilities are monitored for the emergency low and high limit after the second contingency (N-1-1 condition.)

Voltage Collapse

Voltage collapse is considered to be a severe reliability violation, and consequently each N-1-1 condition that exhibits voltage collapse needs to be investigated, validated, and resolved with remedial actions, or network upgrades.

System Adjustments

Allowable System Adjustments following the first contingency (N-1 condition):

- Application of all effective actions and emergency procedures, with the exception of load shedding
- Redispatch using only PJM generators with capacity rights during the generation redispatch process
- Application of a PJM pool-wide generation availability rate during generator re-dispatch to ensure that the re-dispatch is statistically possible
- Un-faulted facilities in multiple facility outages may be restored
- Manual system switching and re-configuration
- Opening of transmission facilities
- Including bus-ties
- Closing of non-faulted transmission facilities
- Including bus-ties
- Adjustment of Static VAR Compensators (SVCs)
- Phase shifter adjustment
- Wind, solar, and other variable resources will be dispatchable up to their capacity delivery rights if they back off simulated facility loadings.
- The rest of resources can be either off line or dispatched between Pmin and (1- PJM generator average outage rate)* Pmax

Allowable System Adjustments following the second contingency (N-1-1 condition):

No manual system adjustments permitted

2.3.9 Load Deliverability Analysis

The load deliverability tests are a unique set of analyses designed to ensure that the Transmission System provides a comparable transmission function throughout the system. These tests ensure that the Transmission System is adequate to deliver each load area's requirements from the aggregate of system generation. The tests develop an "expected value" of loading after testing an extensive array of probabilistic dispatches to determine thermal limits. A deterministic dispatch method is used to create imports for the voltage criteria test. The Transmission System reliability criterion used is 1 event of failure in 25 years. This is intended to design transmission so that it is not more limiting than the generation system which is planned to a reliability criterion of 1 failure event in 10 years.

Each load areas' deliverability target transfer level to achieve the transmission reliability criterion is separately developed using a probabilistic modeling of the load and generation system. The load deliverability tests described here measure the design transfer level supported by the Transmission System for comparison to the target transfer level. Transmission upgrades are specified by PJM to achieve the target transfer level as necessary. Details of the load deliverability procedure can be found in Attachment C.

Thermal

This test examines the deliverability under the stressed conditions of a 90/10 summer and winter load forecast. That is, a forecast that only has a 10% chance of being exceeded. The transfer limit to the load is determined for system normal and all single contingencies (NERC P0 and P1 criteria) under ten thousand load study area dispatches with calculated probabilities of occurrence. The dispatches are developed randomly based on the availability data for each generating unit. This results in an expected value of system transfer capability that is compared to the target level to determine system adequacy. As with all thermal transmission tests applied by PJM the applicable Transmission Owner normal and emergency ratings are applied. The steady state and single contingency power flows are solved consistent with the similar solutions described for the baseline thermal analyses.

Voltage

This testing procedure is similar to the thermal load deliverability test except that voltage criteria are evaluated and that a deterministic dispatch procedure is used to increase study area imports. The voltage tests and criteria are the same as those performed for the baseline voltage analyses.

2.3.10 Generator Deliverability Analysis

The generator deliverability test ensures that the Transmission System is capable of delivering the aggregate system generating capacity at summer peak load with all firm transmission service modeled. Additionally, to help ensure that generating resources are deliverable year round, expected generation output levels during light load and winter conditions are examined as part of the generator deliverability analysis. As a result, there are three separate periods examined as part of the generator deliverability analysis. The procedure ensures sufficient transmission capability in all areas of the system to export an amount of generation capacity at least equal to the amount of certified Capacity Resources in each "area". Areas, as referred to in the generator deliverability test, are unique to each study and depend on the electrical system characteristics that may limit transfer of Capacity Resources. For generator deliverability, areas are defined with respect to each transmission element that may limit transfer of the aggregate of certified installed generating capacity. The cluster of generators with significant impacts on the potentially limiting element is the "area" for that element. The starting point power flow cases for the light load, summer and winter are the same power flow case set up for the baseline analysis, but the applicable baseline load and ratings criteria apply for the period under consideration. The flowgates ultimately used in the reliability analysis are determined by running

all contingencies maintained by PJM planning and monitoring all PJM market monitored facilities and all BES facilities. Single and common mode contingencies (NERC TPL P1, P2, P4 and P7) in PJM and just outside of PJM are examined during the generator deliverability analysis. Details of the generator deliverability procedure including methods of creating the study dispatch can be found in Attachment C.

2.3.11 Spare Equipment Strategy Review

PJM will annually evaluate an entity's spare equipment strategy that could result in the unavailability of major transmission equipment that has a lead time of one year or more (such as a transformer). Steady state analysis is performed for the P0, P1 and P2 planning event categories and stability analysis is performed for the P1 and P2 planning event categories defined in Table 1 of NERC TPL-001-5.1 with the conditions that the system is expected to experience during the possible unavailability of the long lead time equipment.

2.3.12 Baseline Stability Analysis

PJM ensures generator and system stability during its interconnection studies for each new generator. In addition, PJM annually performs stability analysis for approximately one third of the existing generators on the system. Analysis is performed on the RTEP baseline stability cases. These analyses ensure the system is transiently stable and that all system oscillations display positive damping with damping ratio consistent with section G.2.2. Generator stability studies are performed for critical system conditions, which include light load and peak load for three phase faults with normal clearing plus single line to ground faults with delayed clearing. Also, specific Transmission Owner designated faults are examined for plants on their respective systems.

Finally, PJM will initiate special stability studies on an as needed basis. The trigger for such special studies commonly includes but is not limited to conditions arising from operational performance reviews or major equipment outages.

2.3.13 Extreme Event Review

The extreme review identifies specific extreme contingencies as defined in Table 1 of NERC Standard TPL-001-5.1 and assesses their impact on system reliability. If the initial analysis shows cascading caused by the occurrence of extreme events, PJM will perform an evaluation of possible action designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s). This can include a stability analysis of the area and an evaluation of possible actions to reduce the likelihood of the event or mitigate the consequences and impacts on the system.

PJM will also assess the impact of extreme events using stability analysis. Extreme events contained in Table 1 of NERC TPL-001-5.1 that produce more severe impacts shall be identified and a list created of those events will be maintained and distributed to the appropriate entities. The rationale for those contingencies selected for evaluation shall be available as supporting information. If the initial analysis shows cascading by the occurrence of extreme events, PJM

will perform an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s).

2.3.14 Long Term Reliability Review

The PJM RTEP reliability review process examines the longer term planning horizon, which spans the current year plus 6 through the current year plus 15, using a 24-month reliability planning cycle. At the beginning of the first year of the cycle, a 5-year out base case, a long-term 8-year out base case and a 10-year out base case are developed and evaluated. At the beginning of the second year of the cycle, new 5-year out, 7-year out and 10-year out base cases are developed and evaluated. Assumptions and model development regarding this longer term view will be presented and reviewed and stakeholder input will be considered in the same process used for the near-term review. The longer term view of system reliability is subject to increased uncertainty due to the increased likelihood of changes in the analysis as time progresses. The purpose of the long term review is to anticipate system trends which may require longer lead time solutions. This enables PJM to take appropriate action when system issues may require initiation during the near term horizon in anticipation of potential violations in the longer term. System issues uncovered that are amenable to shorter lead time remedies will be addressed as they enter into the near-term horizon. 7 and/or 8 year analysis is only required when 15 year analysis shows potential issues.

Current Year Plus 15 Analysis

The Longer term reliability review involving single and multiple contingency analyses is conducted to detect system conditions which may need a solution with a lead-time to operation exceeding five years. Two processes will be used as indicators to determine the need for contingency analysis in the longer term horizon. The first is a review of the near-term results to detect violations that occur for multiple deliverability areas or multiple or severe violations clustered in a one area of the system. This review may suggest larger projects to collectively address groups of violations. The second is a thermal analysis including double circuit towerline outages at voltages exceeding 100 kV performed on the current year plus fifteen system. All of the current year plus fifteen results produced will be reviewed to determine if any issues may require longer lead time solutions. If so such solutions will be determined and considered for inclusion in RTEP.

This evaluation of the need for longer lead time solutions considers that the NERC P2, P3, P4, P5, P6 and P7 results may employ load shedding and/or curtailment of firm transactions to ease potential violations. Also this review considers that the current year plus fifteen planning horizon exceeds the required NERC planning horizon. The main effect of this extension to 15 years is to examine a load level that is significantly higher than the base forecast year-ten planning load level. This year fifteen analysis, therefore, captures the equivalent (in a 10-year horizon) of a higher load forecast plus weather sensitivity. To the extent that this long term reliability thermal review indicates marginal system conditions that may require a longer lead time solution, PJM will undertake additional longer term analyses as may be needed.

The long term deliverability analyses follow a similar pattern to the near-term load and generator deliverability analyses. The long term, however, relies solely on linear DC analysis whereas all near term violations result from analysis solutions that rely on the full AC power flow. The load deliverability case is set up for a 90/10 load level and the generator deliverability case is set up for a 50/50 load level. Generation dispatches are determined consistent with the methods for the near term analyses. The analysis for the longer term horizon evaluates all NERC P0 and P1 single contingencies against the same normal and emergency thermal ratings criteria used for the near term (subject to any upgrades that may be applicable for the longer term.)

Reactive Analysis

In addition, the longer term review includes a current year plus 10 reactive analysis. This focuses on contingencies involving facilities above 200 kV in areas where the preceding year-15 analysis uncovered thermal violations. Areas experiencing thermal violations that also show earlier reactive deficiencies will be reviewed for possible acceleration of any longer lead time thermal solutions that were suggested by the year-15 analysis. This analysis, as necessary from year to year, will also consider long-term upgrade sensitivity to key variables such as load power factor delivered from the Transmission System or heavy transfers. If uncovered violations are insufficient to justify acceleration of upgrades and are all amenable to shorter lead-time upgrades, then the violations will continue to be monitored in future RTEP analyses.

2.3.15 Stakeholder review of and input to Reliability Planning

RTEP reliability planning, through the operation of the TEAC and Subregional RTEP Committees, provides interested parties with the opportunity to review and provide meaningful and timely input to all phases of the reliability planning analyses. This section extends the Section 1 discussion of the TEAC and Subregional RTEP Committee process specifically as it relates to reliability planning. Exhibit 1 shows the workflow and timing for the reliability planning process steps. PJM anticipates at least two Subregional RTEP Committee reliability reviews. The initial subregional meeting will present and address reliability study assumptions and parameters. The second meeting will provide the opportunity for stakeholder comment and input on criteria violations and presentations of alternative remedies to identified violations. Between the two meetings PJM will provide feedback on interim study progress sufficient to enable stakeholder preparation for the second set of subregional meetings. Additional subregional meetings will be facilitated as PJM determines is necessary for adequate input and review. The relative timing of the TEAC and subregional activities are illustrated in Exhibit 1.

Subregional RTEP Committee initial assumptions meeting

This meeting is expected to occur in ***December*** of each year in preparation for the upcoming annual RTEP review. Prior to the meeting PJM will post its anticipated inputs and assumptions to enable stakeholder review and preparation for the meeting. At the meeting PJM will present the assumptions for discussion and input by all interested parties. Subsequent to this meeting stakeholders will have additional opportunity to provide input to PJM in preparation for the next TEAC meeting, at which PJM will present the final reliability assumptions for TEAC review.

Although the initial Subregional assumptions meeting will discuss anticipated assumptions for both the reliability and market efficiency phase of the RTEP, The final TEAC review of each will likely occur at separate TEAC meetings (see also the market efficiency discussion following.) The TEAC endorsement of final RTEP reliability assumptions is expected to occur in early ***January***.

PJM development of criteria violations and stakeholder participation

After the TEAC endorsement of PJM's RTEP analysis assumptions, PJM will finalize its reference system power flow which is the starting point of its series of reliability analyses. This power flow is available to stakeholders subject to applicable confidentiality and CEII requirements. PJM will perform its series of detailed RTEP reliability analyses encompassing the 15-year planning horizon. Details of the methods and procedures for the reliability analyses can be found elsewhere in this Manual 14B and its attachments. The five-year and longer time-frame criteria violations will be posted for review, evaluation and development of remedy alternatives by all interested parties. The PJM production of the reliability analysis raw results is expected to occur about ***January through July*** of each year. Posting of the results and stakeholder review and consideration of alternative remedies is expected to occur about ***February through August*** of each year. PJM will post TO and other stakeholder alternative upgrade remedies made available throughout this process. Throughout this time frame, TEAC typically has monthly or more frequent regularly scheduled meetings. PJM will periodically apprise TEAC of the progress of the violations identification and production of upgrade alternatives. Stakeholders may use these meetings to raise and discuss issues found in their reviews. Depending on the issues raised and input from stakeholders PJM may facilitate Subregional RTEP Committee meetings instead of or in addition to a scheduled TEAC meeting. These subregional meetings are intended for more focused review of subregional violations and alternative solutions.

Subregional RTEP Committee criteria violations and upgrade alternative meeting

This meeting is expected to occur, as may be necessary in various subregions, in the ***July / August*** timeframe each year. If a subregional meeting is unnecessary, the regularly scheduled TEAC meetings will provide the opportunity for that subregion's participants open discussion of violations and upgrades. In any event, all regional and subregional projects will be appropriately presented and reviewed at a TEAC meeting. Prior to a subregional violations and upgrade meeting, PJM will post the upgrade solutions that it proposes to remedy the identified criteria violations. At this subregional meeting PJM will present the reliability upgrades of specific violations and alternative upgrades as may be appropriate. By this Subregional RTEP Committee meeting, interested parties will have had the opportunity for ongoing participation in the ***February through August*** process of violation review and solution identification along with PJM and Transmission Owners. This subregional criteria violations and upgrade meeting is the forum for a final open discussion of the subregional reviews which have been occurring, prior to presentation to TEAC.

PJM TEAC Committee RTEP review

PJM expects that about ***August*** of each year, the final RTEP upgrade facilities will be available for presentation, review and endorsement at a scheduled TEAC meeting. PJM will post its recommendations of RTEP upgrades for identified violations as early as possible in the month prior to the TEAC meeting at which the final RTEP facilities will be reviewed (see RTEP@pjm.com). This posting will distinguish facilities that are deemed Supplemental RTEP Projects. After the TEAC RTEP review meeting, there will be about a month of additional time for final written comments on the proposed RTEP facilities, after which the PJM Board will consider the final RTEP plan excluding Supplemental Projects for approval.

2.3.16 Corrective Action Plan

PJM will prepare an annual Planning Assessment of its portion of the BES. For planning events shown in Table 1, when the analysis indicates an inability of the system to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned system shall continue to meet the performance requirements in Table 1. The Corrective Action Plan shall list system deficiencies and associated actions need to achieve required system performance. Examples of such actions include:

- Installation, modification, retirement or removal of Transmission and Generation facilities and any associated equipment
- Installation, modification or removal of Protection Systems or Remedial Action Schemes.
- Installation or modification of automatic generation tripping as a response to a single or multiple contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan

Additionally, the Corrective Action Plan shall include action to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.4 RTEP integrates Baseline Assumptions, Reliability Upgrades and Request Evaluations

PJM's robust energy market has attracted numerous requests from generator and transmission Project Developers for interconnections with the Transmission System. These Interconnection Requests constitute a significant driver of regional transmission expansion needs. This

subsection discusses this driver in the context of the RTEP preparation. Details of this process are contained in Manual 14H.

Requests for Long Term Firm Transmission Service and generator deactivations are other types of request that are evaluated and incorporated into RTEP.

Demand Response (DR) can be a load response solution to the need for transmission upgrades. DR solutions enter the PJM process in the Reliability Pricing Model (RPM) through the associated base residual and incremental auctions. The DR cleared in the auction is included in the assumptions for RTEP development and physically modeled in the baseline power flows. In this manner, load can mitigate or delay the need for RTEP upgrades.

The RTEP process baseline analyses include previously processed generators and transmission modifications as starting point assumptions. The current year RTEP evaluations performed on this baseline case are incremental to the baseline and establish a “revised” baseline for the year of the annual RTEP analysis. This revised baseline forms the starting case for the reviews of new interconnection requests. The new interconnection request analyses result in system modifications beyond RTEP upgrades that are caused by interconnection requests. New interconnection request evaluations also include a review of their effects on newly approved RTEP upgrades that are not yet committed to construction. If previously identified RTEP upgrades can be delayed because of new interconnection requests, the projects responsible for the upgrade deferrals will be credited for the benefits of the delayed need for the upgrades.

The RTEP integrates reliability upgrades, interconnection request upgrades and plan modifications and DR effects into a single process that accounts for the mutual interaction of the various market forces. In this way, transmission upgrades, interconnection requests and DR receive comparable treatment with respect to their opportunity to relieve transmission constraints.

Timing of Long-Term Firm Transmission Service Requests, and Generation and Transmission Interconnection Requests are based on the business needs of the party requesting the service. Such requests, therefore, enter the RTEP planning process throughout the RTEP planning year. Expansion plans that result from New Service Request evaluations are incorporated into the RTEP once a New Service Request’s applicable final agreement has been executed. In addition, if needed to satisfy assumed planning reserve requirements for future planning year analyses, generators in Phase III System Impact Study may also be included. Only the generators with completed signed final agreements, however, are allowed to be used to alleviate constraints.

2.5 RTEP Cost Responsibility for Required Enhancements

The RTEP encompasses two types of enhancements: Network Reinforcements and Direct Connection Attachment Facilities. Network Reinforcements can be required in order to

accommodate the interconnection of a merchant project (generation or transmission) or to eliminate a Baseline problem as a result of system changes such as load growth, known transmission owner facility additions, etc. Merchant project driven upgrades are addressed in Manual 14H. The cost responsibility for each baseline-revealed Network Reinforcement is borne by transmission owners based on the contribution to the need for the network reinforcement. Such costs are recoverable by each transmission owner through FERC-filed transmission service rates. Network reinforcements may also be proposed by PJM to mitigate unhedgeable congestion. Allocation procedures for Baseline and Market Efficiency upgrades are discussed in Attachment A.

Overall, the RTEP is best understood from the perspective of the studies that revealed the recommended Plan enhancements. To that end, the Baseline Analysis and Impact Studies identify the enhancements required to meet defined NERC and applicable regional reliability council (Reliability First or VACAR/SERC) standards, Nuclear Plant Licensee requirements and PJM reliability standards.

2.6 RTEP Market Efficiency Planning

Market efficiency analysis is performed as part of the overall PJM Regional Transmission Expansion Planning (RTEP) process to accomplish the following objectives:

- Identify new transmission enhancements or expansions that could relieve transmission constraints that have an economic impact.
- Review cost and benefits of economic-based transmission projects previously included in the Regional Transmission Expansion Plan (RTEP) to assure that they continue to be cost beneficial.
- Determine which reliability-based transmission projects, if any, have an economic benefit if accelerated or modified

Each year, as part of the 24-Month Market Efficiency Cycle, PJM performs a market efficiency analysis following the completion of the near-term reliability plan for the region. As a result, there is a mechanism in place for regularly identifying transmission enhancements or expansions that will relieve transmission constraints that also have an economic impact. Constraints that have an economic impact include, but are not limited to, constraints that cause: (1) significant historical gross congestion; (2) pro-ration of Stage 1B ARR; (3) significant future congestion as forecast in the market efficiency analysis; or (4) Reliability Pricing Model constraints identified in accordance to OATT Attachment DD Section 15.

In the market efficiency analysis, PJM will compare the costs and benefits of the economic-based transmission improvements. To calculate the benefits of these potential economic-based enhancements, PJM will perform and compare market simulations with and without the proposed accelerated reliability-based enhancements or the newly proposed economic-based enhancements for selected future years within the planning horizon of the RTEP. The relative benefits and costs of the economic-based enhancement or expansion must meet the benefit/

cost ratio threshold test to be included in the RTEP recommended to the PJM Board of Managers for approval (This test and its implementation is described in detail in Attachment E.) PJM will present all the RTEP market efficiency enhancements to the TEAC Committee for review and comment. Subsequent to TEAC review, PJM will address the TEAC review and present the final RTEP market efficiency plan to the PJM Board, along with the advice, comments, and recommendations of the TEAC Committee, for Board approval.

2.6.1 Market Efficiency Analysis and Stakeholder Process

PJM's market efficiency analysis involves several phases. The process begins with the determination of the congestion drivers that may signal market inefficiencies. PJM will collect and publicly post relevant drivers. These metrics will be reviewed by PJM and all stakeholders to assess the system areas that are most likely candidates for market efficiency upgrades. In addition, PJM will perform market simulations to determine projections of future market congestion based on the anticipated RTEP upgraded system. This process facilitates concurrent PJM and stakeholder review of the same information considered by PJM in preparation for PJM's solicitation of stakeholder input for upgrades that may economically alleviate market inefficiencies. This solicitation of input will be at a Transmission Expansion Advisory Committee meeting. Following the evaluation of congestion drivers and solicitation of remedies, PJM will initiate an analysis phase which first examines the potential economic costs and benefits that may be associated with any upgrades specified during the reliability analysis. After this assessment, PJM will evaluate the economic costs and benefits of any identified new potential upgrades target specifically at economic efficiency. The following information looks at each of these phases in more detail.

2.6.2 Determination and evaluation of historical congestion drivers

Transmission solutions to mitigate congestion causing a pro-ration of existing or future Stage 1A ARR requests will be determined and recommended for inclusion in the RTEP with a recommended in-service date based on the 10-year Stage 1A simultaneous feasibility analysis results. This recommendation will also include a high-level analysis of the cost and economic benefits of the upgrade as additional information but such upgrades will not be subject to market efficiency cost/benefit analysis. More information on the ARR allocation auction process can be found in Manual 6.

Congestion causing pro-ration of Stage 1B ARR requests will be addressed using the "with and without" analysis and the benefit/cost ratio threshold described previously in this market efficiency material.

2.6.3 Determination of projected congestion drivers and potential remedies

PJM will provide all stakeholders with estimates of the projected congestion by performing annual hourly market simulations of future years using a commercially available market analysis software modeling tool (see assumptions and criteria material in Section 1.) This simulation will produce and PJM will post projected binding constraints, binding hours, average economic

impact of binding constraints, and cumulative economic impact of binding constraints for the four RTEP market efficiency analyses.

At this time PJM will also facilitate a TEAC meeting, as appropriate, to review congestion and solicit feedback from the stakeholders' review of the projected congestion data. All stakeholders can provide input to PJM's consideration of the congestion data to be considered for market efficiency solutions to identified economic issues.

Parties wishing formally to submit proposals to address congestion as identified in the Market Efficiency Analysis may do so as described in section 2.6.7 of this manual.

2.6.4 Evaluation of cost / benefit of advancing reliability projects

PJM will perform annual market simulations and produce cost / benefit analysis of advancing reliability projects. An initial set of simulations will be conducted for current year plus 1 and current year plus 5 using the "as is" transmission network topology without modeling future RTEP upgrades. A second set of simulations will be conducted for each year using the as planned RTEP upgrades. A comparison of the "as is" and "as planned" simulations will identify constraints which have caused significant historical or simulated congestion costs but for which an as-planned upgrade will eliminate or relieve the congestion costs to the point that the constraint is no longer an economic concern. A comparison of these simulations will also reveal if a particular RTEP upgrade is a candidate for acceleration or expansion. For example, if a constraint causes significant congestion in year 1 but not in year 5 then the upgrade which eliminates this congestion in the year 5 simulation may be a candidate for acceleration. The benefit of accelerating this upgrade would then be compared to the cost of acceleration as described below before recommendation for acceleration is made.

When the reliability project economic acceleration analyses have been completed, PJM will schedule a TEAC or Subregional Committee meeting, as appropriate, to review the results. The timing of this meeting will depend, to some extent, on the amount and complexity of analysis that must be performed. However, it is anticipated that this meeting will take place during the ***fourth quarter*** of each year. At this meeting PJM will provide a summary of the analysis results, including an update of the Market Efficiency analysis and a description of any recommendations for accelerating reliability projects based on economic considerations.

2.6.5 Determination and evaluation of cost / benefit of potential RTEP projects specifically targeted for economic efficiency

PJM will perform market simulations and produce cost / benefit analysis of projects specifically targeted for economic efficiency. The benefit component of the cost / benefit analysis (Total Annual Enhancement Benefit) could consist of an energy market benefit, a Reliability Pricing Model (RPM) benefit, or both if the project addresses both energy market and RPM constraints. The net present value of annual benefits will be calculated for the 15 year period starting with the RTEP year defined as current year plus 5 minus benefits for years where the project is not

yet in service. The net present value of annual benefits will be compared to the net present value of the upgrade revenue requirement for the same 15 year period.

2.6.5.1 Determination of Energy Market Benefits

An initial set of simulations will be conducted for each of four years for the current 24-month cycle (current year plus 1, current year plus 5, current year plus 8 and current year plus 11) using the as planned transmission network topology and the as planned generation expansion as defined by the most recent RTEP. A second set of simulations will be conducted for each of the four years using the as planned transmission network topology plus the upgrade being studied. The upgrade will be included in each of the four simulation years regardless of the actual anticipated in-service date of the upgrade. A comparison of these simulations will identify the benefit of the upgrade in each of the four years analyzed. The simulated benefits will provide a forecast of annual upgrade benefits for each of the anticipated first 15 years beginning from the RTEP year. Annual benefits within the 10-year time frame for years which were not simulated would be interpolated using these simulation results. A forecast of annual benefits for years beyond the 10-year simulation time frame would be based on an extrapolation of the market simulation results from the studied years. A higher-level annual market simulation will be made for future year 15 to validate the extrapolation results and the extrapolation of annual benefits for years beyond the 10-year simulation time frame may be adjusted accordingly. This high level simulation of future year 15 may require a less detailed model of the transmission system below the 500 kV level.

2.6.5.2 Determination of Reliability Pricing Model (RPM) Benefits

To determine RPM benefits, PJM will perform and compare RPM simulations with and without the upgrade for the RPM year (current year plus 3) and the RTEP year (current year plus 5). A comparison of these simulations will identify the annual economic impact of the upgrade for each of these study years. A forecast of annual benefits for years beyond the RTEP year will be based on a linear extrapolation of the market simulation results from the studied years.

2.6.5.3 Determination of Benefits/Cost ratio

An extrapolation of the simulation results will provide a forecast of annual upgrade benefits for each of the 15 years, beginning from the RTEP year. The present value of annual benefits projected for the 15 year period starting with the RTEP year defined as current year plus 5 minus benefits for years where the project is not yet in service will be compared to the present value of the upgrade revenue requirement for the same period to determine if the upgrade is cost beneficial and recommended for inclusion in the PJM RTEP. For informational purposes only, when comparing competing projects PJM will set the annual revenue requirement for projects not yet in service to zero and include annual benefits as a negative number to reflect loss of benefits to PJM. If the ratio of the present value of benefits to the present value of costs exceeds 1.25 then the upgrade is recommended for inclusion in the RTEP.

When the economic efficiency project evaluations have been completed, PJM will schedule a TEAC meeting, as appropriate, to review the results. The timing of this meeting may depend on the amount and complexity of analysis that must be performed. At this meeting PJM will provide a summary of the analysis results, including an update of the Market Efficiency analysis.

2.6.6 Determination of final RTEP market efficiency upgrades

PJM will perform a combined review of the accelerated reliability projects and new market efficiency projects that passed the economic screening tests to determine if there are potential upgrades with electrical similarities. This may result in new projects to replace the original projects to form a more efficient overall market solution. PJM will evaluate the cost / benefits of any such resulting "hybrid" projects[3]. The final list of reliability projects and market efficiency projects, including any "hybrid" projects will be presented and discussed at a TEAC meeting. At this TEAC meeting PJM will review all the Market efficiency plans resulting from this cycle of market efficiency studies. Recommended projects will be taken to the PJM Board for endorsement, and will either be included in subsequent RTEP analysis if there is a "volunteer" to build the project, or a report will be filed with FERC in accordance with Schedule 6 of the PJM Operating Agreement. As part of this request for endorsement, PJM will provide the written comments submitted by the parties, and will discuss these written comments with the PJM Board.

Within the limits of confidential, market sensitive, trade secret, and proprietary information, PJM will make all of the information used to develop the Market Efficiency recommendations available to market participants to use in their own, independent analyses.

For each enhancement which is analyzed, PJM will calculate and post on its website changes in the following metrics on a zonal and system-wide basis: (i) total energy production costs (fuel costs, variable O&M costs and emissions costs); (ii) total load energy payments (zonal load MW times zonal load Locational Marginal Price); (iii) total generator revenue from energy production (generator MW times generator Locational Marginal Price); (iv) Financial Transmission Right credits (as measured using currently allocated Auction Revenue Rights plus additional Auction Revenue Rights made available by the proposed acceleration or modification of a planned reliability-based enhancement or expansion or new economic-based enhancement or expansion); (v) marginal loss surplus credit; and (vi) total capacity costs and load capacity payments under the Reliability Pricing Model construct.

3 Hybrid transmission upgrades include solutions which encompass modification to reliability-based enhancements already included in RTEP that when modified would relieve one or more economic constraints. Such hybrid upgrades resolve reliability issues but are intentionally designed in a more robust manner to provide economic benefits in addition to resolving those reliability issues.

For each market efficiency project proposed for RTEP, PJM will also post, as soon as practical, the following:

- Anticipated high-level project schedule and milestone dates
- Final commitment date after which any change to input factors or drivers will not result in transmission project deferral or cancellation.

After this TEAC meeting, any member of the TEAC can provide written comments within sixty (60) days of this meeting. These written comments will consist of three (3) sections:

- Introduction, which will describe the party submitting the comments and their reason for submitting these comments
- Summary, which will consist of no more than 3 pages summarizing the positions described in the written comments
- Discussion, which will consist of no more than 20 pages describing in detail the positions taken by the party

2.6.7 Submitting Proposals

Any TEAC member or other entity (consistent with PJM Operating Agreement Schedule 6 provisions), may formally submit proposals for evaluation under the Market Efficiency analysis within the RTEP proposal window. These proposals will be posted on the PJM Website. Market Efficiency Proposals will not be accepted for acceleration or modifications to existing approved RTEP projects.

Regardless of all proposals considered – whether proposed by PJM or other parties - PJM will establish a “go/no-go” decision-point deadline (or final commitment date) after which existing RTEP transmission components will not be deferred or cancelled. This will provide certainty to developers, owners and investors.

2.6.8 Ongoing Review of Project Costs

To assure that projects selected by the PJM Board for Market Efficiency continue to be economically beneficial, both the costs and benefits of these projects will be reviewed on an annual basis. Substantive changes in the costs and/or benefits of these projects will be reviewed with the TEAC at a subsequent meeting to determine if these projects continue to provide measurable economic benefit and should remain in the RTEP.

For Market Efficiency projects included in the RTEP with capital costs under $20M, PJM will not be required to reevaluate both updated costs and benefits annually if the project’s benefit/cost ratio remains at or above 1.25, using the original benefits. However, if the benefit/cost ratio of such projects falls below 1.25 based on PJM’s annual review of the project’s updated cost estimate, PJM will reevaluate the need for the project using both updated cost estimates and benefits.

PJM will no longer be required to review updated costs and benefits of a market efficiency project once the certificate of public convenience and necessity or its equivalent is granted by the state in which the facilities will be located. If no certificate of public convenience or necessity or its equivalent is required by the state in which the transmission facilities will be located, PJM will no longer be required to review updated costs and benefits of a market efficiency project once the project commences construction activities at the project site. Notwithstanding the foregoing, PJM reserves the right to reevaluate any project.

For projects with a total cost exceeding $50 million, an independent review of project costs and benefits will be performed to assure both consistency of estimating practices across PJM and that the scope of the project is consistent with the project as proposed in the Market Efficiency analysis.

2.7 Evaluation of Operational Performance Issues

As per Schedule 6, section 1.5 of the PJM Operating Agreement, PJM is required to address operational performance issues and include system enhancements, as may be appropriate, to adequately address identified problems. To fulfill this obligation, PJM Transmission Planning staff and Operations Planning staff annually review actual operating results to assess the need for transmission upgrades that would address identified issues. Typical operating areas of interest in these reviews include Transmission Loading Relief (TLR), Post Contingency Local Load Relief Warning (PCLLRW) events, and persistent uplift payments.

The first operational performance issue to be addressed through the RTEP was an upgrade of the Wylie Ridge 500/345 kV transformation. The metric applied to designate Wylie Ridge an operational performance issue was the TLR metric. This same metric is applied consistently across the PJM footprint.

In addition, PJM has also developed and initiated use of a tool for Probabilistic Risk Assessment (PRA) of transmission infrastructure. PJM's 500/230 kV transformer infrastructure has been identified as particularly suited for assessment using this tool. PRA is further discussed in following sections.

2.7.1 Operational Performance Metrics

Events and metrics considered in the annual operational performance reviews are not limited to a specifically defined list and will be responsive to events and conditions that may arise. In addition, PJM stakeholders may raise operational issues to PJM's attention for consideration during the RTEP process through interactions with the Planning, TEAC or Subregional RTEP Committees.

The PJM TLR metric identifies facilities that result in over 1,000 hours or 100 occurrences of TLR level 3 or higher on an annual basis. These facilities will be evaluated through the RTEP process for system enhancement.

For PCLLRW events, PJM will review all such events after the conclusion of the peak season. The initiating facilities will be determined and the expected impacts of planned RTEP upgrades will be reviewed and the need for additional planned upgrades will be evaluated.

For Uplift payments, PJM will annually review the persistent uplift payments and the system condition or driver for the payment. PJM will assess the impact of planned RTEP upgrades on the drivers for the uplift and the need for additional planned upgrades will be evaluated. The evaluation of the need for additional upgrades will consider the frequency and amount of the uplift payment as well as any outage or short term system conditions that may have caused the uplift. Upgrades will be considered to mitigate uplift payments that are expected to continue in the future.

PRA evaluation uses an economic analysis of the cost of the investment that mitigates a risk and the dollar value of the avoided risk. The mitigation strategy cost, prime rate and payback period are used to determine if the strategy cost is less than the value of risk. Projects with lower cost than risk are candidates for the RTEP.

2.7.2 Probabilistic Risk Assessment of PJM 500/230 kV Transformers

One significant element of PJM's operational performance reviews involves a risk evaluation aimed at anticipating significant transmission loss events. PJM integrates aging infrastructure decisions into the ongoing RTEP process: analysis, plan development, stakeholder review, PJM Board approval, and implementation, over PJM's entire footprint. Thus, the aging infrastructure initiative implements a proactive, PJM-wide approach to assess the risk of transmission facility loss and to mitigate operational and market impacts of such losses.

PRA's initial implementation at PJM is a risk management tool employed to reduce the potential economic and reliability consequences of transmission system equipment losses. In collaboration with academia, vendors and member TOs, PJM integrated various input drivers into a transformer PRA initiative to manage 500/230 kV transformer risk. In the case of the 500/230 kV transformers, risk is the product of the probability of incurring a loss and the economic consequence of the loss. Probability of loss is determined based on the individual transformer unit's condition assessments and vintage history. Economic loss impact is based upon the duration of the loss and the accumulation of unhedgeable congestion costs, or the increased cost of running out of merit generation to meet load requirements after a transformer loss. If lead times for 500/.230 kV transformer units are as great as eighteen months, then outage durations can be long if adequate loss mitigation is not in place. The PRA outputs the annual risk to the PJM system of each transformer unit in terms of dollars. The annual risk dollars are then used to justify mitigating solutions such as redundant bank deployment, proactive replacement or adding spares. The deployment strategy chosen will depend on the level of risk mitigation and reliability benefit.

While initially developed for aging 500/230 kV transformers, the PRA tool is capable of assessing other equipment types and other transformer voltage classes. The PRA tool is commercially available software.

2.8 End of Useful Life Issues

For each transmission need identified pursuant to FERC Form No. 715 or other Transmission Owner planning criteria addressing the end of useful life of an existing facility, which, in accordance with good utility practice, is not determined by the facility's service life for accounting or depreciation purposes, each Transmission Owner should provide information, to the extent available, that supports the need for the project consistent with the Transmission Owner's planning criteria in accordance with the RTEP process or Attachment M-3 Process, as applicable.

2.9 Critical Substation Planning Analysis

PJM will evaluate all proposed system reinforcements, consistent with RTEP critical substation planning analysis methods incorporated in cascading trees tool software. This analysis is performed as part of the 5 year annual RTEP cycle, as described in Section 2.3.3 of this manual, to determine if any projects addressing other drivers cause concern from a critical substation planning analysis perspective.

Critical substation planning analysis is performed to identify Instability, Uncontrolled Separation, or Cascading resulting in one or more of the following outcomes due to the loss of all voltage levels 69 kV and above at a single transmission facility that has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation:

Voltage Value of a Line	Weight Value per Line
Less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

1. Loss of load approaching 1000 MW impacting numerous customers
    - Includes consequential load loss and tripped load
    - Total loss of load should be considered
2. Three levels of facility trips
    - Includes line, transformers and generators
    - Tripped elements should include 69kV and above facilities.
3. Case fails to converge after tripping of facilities, assuming non-convergence isn't due to modeling issues or load pockets

If a proposed project fails the critical substation planning analysis, PJM may modify the technical specifications of a proposal so that is avoids a failure of the critical substation planning analysis (CSPA), as defined above in this Section 2.9. This may result in the modified proposal being determined to be the more efficient or cost-effective proposal for recommendation to the PJM Board.

Attachment A: PJM Baseline Reliability Upgrade Cost Allocation Procedures

A.1 Purpose

One of the responsibilities of PJM as an RTO is to allocate the cost responsibility for all system reinforcement projects including projects required for Customer interconnection requests and baseline transmission reliability upgrades. Manual 14H addresses request-driven upgrade cost allocation procedures. The cost allocation procedures used by PJM for baseline reliability upgrades are described below. The methodology in Schedule 12 of the PJM Tariff that is the bases of these cost allocation procedures was developed and filed by the PJM Transmission Owner and approved by FERC for PJM implementation.

A.2 Scope

The PJM Cost Allocation Procedures are presented in two parts: “PJM Generation and Transmission Interconnection Cost Allocation Methodologies” discusses the cost allocation methodology for projects required for generator and transmission interconnections in Manual 14H and: “Schedule 12 Cost Allocation Process for Baseline Transmission Reliability” describes the cost allocation methodology and procedures for baseline transmission reliability projects.

A.3 Schedule 12 Cost Allocation Process for Baseline Transmission Reliability Upgrades

In addition to allocating the costs of interconnection projects (described above), PJM is responsible, under Schedule 6 of the Operating Agreement and Schedule 12 of the Tariff, for determining the cost allocation of all RTEP baseline reliability upgrades and submitting them to the PJM Board for approval. Allocation of transmission upgrades for reliability is beneficiary based. With respect to reliability projects, while a definitive benefit is from the elimination of a reliability criteria violation, the benefit quantified for the purpose of cost allocation is the use of the upgrade by PJM load zones. The usage of the reliability project by a PJM load zone relative to the usage by all other PJM load zones will be used to determine the percentage cost responsibility to be assigned to the zone. As the usage changes with system topology changes, PJM shall recalculate the cost allocation percentage on an annual basis

A.3.1 RTEP Baseline Reliability Upgrade Cost Allocation

PJM’s allocation of cost responsibility for RTEP reliability baseline upgrades in accordance with these provisions is beneficiary based. Typically, load growth creates conditions that constitute violations of reliability criteria, which in turn require upgrades for eliminating the violations. The benefit to load from elimination of the violation will differ from the benefit of having the resultant

upgrade available for use to deliver PJM generation to serve them. However, the benefit derived by the load in a transmission zone can only be determined by the use of the upgrade to deliver PJM generation to this load zone relative to similar uses of the upgrade by other zonal loads. This quantifiable benefit is then used to determine the relative responsibility for the cost of the system upgrade(s) for each zone.

To the extent that a criteria violation is based on the thermal limits of a transmission facility, the cost allocation is based directly on the relative use of the upgrade facility by the load in each zone. However, for criteria violations based on voltage criteria, thermal surrogates are developed and employed for the allocation such that the flow on the surrogate (i.e., a transmission facility or group of facilities) best correlates to the reactive performance of the system at the point of the criteria violation. The same approach described above is then utilized to simulate the relative use of the thermal surrogates. Accordingly, the cost allocation for the solution to the voltage criteria violation is based on the relative use of thermal surrogates by load in each zone.

Under this approach to cost allocation, it is entirely possible, and certainly consistent with the allocation philosophy, that the costs of upgrades in one transmission zone may be allocated in significant part to load in other transmission zones. While many required transmission upgrades are allocated entirely to load within the same zone where the criteria violation and the related upgrade are located, the nature of large, integrated transmission systems like the PJM system is such that transmission facilities in one area can be used significantly to serve loads in other areas. The planning process identifies the most effective solutions to criteria violations and the resultant use of these solutions by loads may not be related to the physical location of the transmission upgrade. Therefore, responsibility for the costs of baseline reliability upgrades likewise shall be allocated to those who use these solutions, regardless of their physical location relative to the location of the baseline reliability upgrade required to ensure the reliability of their service.

The basic categories of baseline reliability upgrades and the associated cost allocation procedures can be summarized as follows:

Regional and Necessary Lower Voltage Facilities with estimated costs greater than or equal to $5 million

50% of the cost of the upgrade will be assigned annually on a load-ratio share using the PJM Network Transmission Service Peak Load and the applicable load values for Merchant Transmission having Firm Transmission Withdrawal Rights for the 12-month period ending October 31 preceding the calendar year for which the annual cost responsibility allocation is determined

50% of the cost of the upgrade will be assigned annually on a directionally-weighted solution-based DFAX methodology

Lower Voltage Facilities with estimated costs greater than or equal to $5 million

100% of the cost of the upgrade will be assigned annually on a directionally-weighted solution-based DFAX methodology

The above allocation method accounts for the bi-directional hourly use of the upgrade. The percentage of net energy flow on the facility in each direction will be determined via an 8,760 hourly production cost simulation. Those load zones having distribution factors that indicate they contribute to power flow on the facility in the same direction as the net energy flow from the production cost simulation will be responsible for the portion of the cost assigned to the use of the upgrade in that direction.

Lower Voltage Facilities with estimated costs below $5 million

100% of the cost will be assigned to the zone where the upgrade is to be located

The basic steps of the directionally-weighted, solution-based DFAX methodology are:

- Obtain peak MW loads from the most recent PJM load report

Calculate the Distribution Factor (DFAX) for each transmission zone and merchant transmission facility with firm withdrawal rights based on its use of the upgrade to deliver PJM generation to serve its load. PJM will use the annual RTEP starting base case to develop all DFAX values for new RTEP upgrades. Other than the addition of new RTEP upgrades, the starting base case will not be modified during the year. A DFAX represents a measure of the use of the upgrade by each MW of a zone's load served by a MW of PJM generation, as determined by power flow analysis. The source used for the DFAX calculation is the aggregate of all PJM generation and the sink is each Transmission Owners peak zonal load or applicable MW values for a merchant transmission with firm withdrawal rights. The import objective to the Locational Deliverability Areas (LDA) in which the transmission zone is located will also be considered during DFAX calculation as follows. In modeling the system generation and load, the percentage of the zonal load in the LDA served by external (or internal) generation to the LDA is the external (or internal) Participation Factor and shall equal the ratio of (i) the CETO associated within that LDA (or generation internal to the LDA) to (ii) the sum of (a) the internal generation within the LDA and (b) the CETO associated with that LDA. For the generation dispatch used in calculating the distribution factor, PJM shall distribute these amounts of external/internal generation among all generation in the PJM Region external to/internal within the LDA, respectively, in proportion to their capacity.

The following example demonstrates the usage of CETO in the calculation of the internal and external Participation Factors described above. In LDA 1, for example, 66.67% of the zonal load in the LDA is served by internal generation and 33.33% of the zonal load in the LDA is served by external PJM generation.

Table 1 - CETO Application in Participation Factor Calculation for Cost Allocation

AREA	LDA 1	LDA 2	LDA 3	LDA 4
CETO (MW)	3,000	6,000	< 0	3,000
Actual Capacity (MW)	6,000	3,000	6,000	0
Internal Participation Factor	66.67%	33.33%	100.00%	0.00%
External Participation Factor	33.33%	66.67%	0.00%	100.00%

- Apply a DFAX threshold of 0.01 such that and DFAX with a magnitude less than 0.01 will be set to zero.

Select the DFAX with the lowest magnitude for zones with more than one DFAX for a particular upgrade as these zones are embedded in multiple LDAs.

- Multiply each DFAX by each zonal peak load to determine the zone's use of the upgrade in the direction indicated by the sign of the DFAX.
  - Sum the MW use of the upgrade corresponding to the same directional use of the upgrade.
  - Calculate the percentage use by each zone in each direction.
- Perform a separate 8,760 hour production cost simulation to determine the expected total energy (MH-Hour) use of the upgrade in each direction for the simulated year.
- Calculate the weighting factor (in percent) for each directional use of the upgrade.
- Calculate the cost allocation percentage from the solution-based DFAX method by multiplying the percentage use of each zonal load in each direction with the weighting factor having the same directional use of the upgrade.

RTEP Baseline Reliability Upgrade Cost Allocation Representative Example

The following representative example illustrates the cost allocation steps.

Step	Reference	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Total
1. Peak Load (MW)	From PJM Load Report	10,000	6,000	4,000	3,000	2,000	25,000
2. DFAX	From DFAX Analysis	0.050	-0.100	0.009	-0.030	0.100	
2a. Apply DFAX Threshold	Set |DFAX| < 0.01 to 0	0.050	-0.100	0	-0.030	0.100	
2b. Select lowest DFAX		0.050	-0.100	0	-0.030	0.100	
3. Zonal Use of the Upgrade	Line 1 * Line 2b	500	(600)	-	(90)	200	
3a. Zonal Use in [+] Direction		500	-	-	-	200	700
3a. Zonal Use in [-] Direction		-	(600)	-	(90)	-	(690)
3b. % use in [+] Direction	Line 3a / Line 3a Total	71.43%				28.57%	100%
3b. % use in [-] Direction	Line 3a / Line 3a Total	-	86.96%	-	13.04%	-	100%
4a. Weighting Factor in [+] direction	From Production Cost simulation	80%	-	-	-	80%	
4a. Weighting Factor in [-] direction	From Production Cost simulation	-	20%	-	20%	-	
5. Calculate cost allocation Percentage	Line 3b * Line 4a	57.14%	17.39%	-	2.61%	22.86%	100%

*For regional and Necessary Lower Voltage facilities greater than or equal to $5 Million, the allocation for each LDA will be the average of the DFAX allocation and the LDA load ratio share based on the appropriate Network Service Peak Loads.

Attachment B: Regional Transmission Expansion Plan—Scope and Procedure

B.1 Purpose

The purpose of the Regional Transmission Expansion Plan (RTEP) is to develop plans which will assure reliability and meet the demands for firm transmission service in the PJM Region as described in Schedule 6 of the Operating Agreement.

B.2 Scope

As part of its ongoing responsibility, PJM Interconnection, LLC (PJM) will prepare a Regional Transmission Expansion Plan (RTEP) which shall consolidate the transmission needs of the region into a single plan. The RTEP shall reflect transmission enhancements and expansions, load and capacity forecasts, and generation additions and retirements for the ensuing five years. The RTEP shall also reflect new transmission construction and right-of-way acquisition required to support load growth in years 6 through 15.

The RTEP will:

- Provide a 5-year plan (“near term plan”) to address needs for which a commitment to expand or enhance the transmission system must be made in the near term in order to meet scheduled in service dates.
- PJM will develop the necessary documentation of previous year’s RTEP analyses and updates to demonstrate compliance with applicable criteria. Such documentation may include the most recent Baseline study for each year in the near-term planning horizon (current year through current year plus 5,) annual changes to each year’s baseline study assumptions for generation, transmission and load compared to the current year's assumptions for each respective study year, and retool studies to evaluate and ensure compliance with applicable standards and criteria for significant changes proposed to the system (Interconnection and New Service Requests.) The need for additional baseline retools will be considered and any needed restudy will be performed and reported. Retool analysis is used to review previously established assumptions, later in the planning cycle, as those assumptions may have changed.
- Provide a 15-year plan (“long term plan”) to address new transmission construction and right-of-way acquisition. System evaluations will be performed to:
    - Identify overloads 230 kV and above due to load growth for years 6 through 15. This will be completed using DC analysis only.
    - Include in the RTEP any new 230 kV or 345 kV circuits identified as required to support load growth in years 6 through 8.

- Include in the RTEP any right-of-way acquisition required for any new 230 kV or 345 kV circuits identified as required to support load growth in years 9 and 10.
- Include in the RTEP any new circuits 500 kV or greater identified as required to support load growth in years 6 through 12.
- Include in the RTEP any right-of-way acquisition required for any new circuits 500 kV or greater identified as required to support load growth in years 13 through 15.

- Include reactive planning to determine if any new transmission identified in the 15-year plan should be accelerated to mitigate identified voltage criteria violations. Additional details for the reactive planning follow:
  - Development of a 10-year RTEP base case that will include Transmission Owner reactive plans.
  - The long term plan voltage analysis will be performed using contingencies 345 kV and greater and monitoring substation voltages 345 kV and greater. Analysis of lower voltage systems will be completed on an exception basis only.
  - Voltage analysis will be performed for areas where PJM identified thermal problems in years 6 through 15 or other areas as identified by PJM.
  - Based on the results of the voltage analysis, PJM will recommend appropriate modifications to the RTEP through the Transmission Expansion Advisory Committee.
- Provide an assessment based on maintaining the PJM region's reliability in an economic manner.
- Avoid any unnecessary duplication of facilities.
- Avoid the imposition of unreasonable costs on any Interconnected Transmission Owner (ITO) or any user of transmission facilities.
- Take into account the legal and contractual rights and obligations of the Interconnected Transmission Owners.
- Provide, if appropriate, alternative means for meeting transmission needs in the PJM Region.
- Provide for coordination with existing transmission systems and with appropriate interregional and local expansion plans.
- Include a designation of the Interconnected Transmission Owner or Owners or other entity that will own a transmission facility and how all reasonably incurred costs are to be recovered.
- Identify local system limitations discovered in analyzing the Transmission System.
- Include Scenario Planning evaluations beginning in mid-2006. Scenario Planning examines the long-term impacts on the reliability of the PJM system from uncertainty with respect to certain assumptions implicit in the development of the RTEP. PJM will examine the effects of uncertainty with respect to selected variables such as economic growth effect on the Load Forecast, Circulating transmission flow effects on system deliverability and generation scaling sensitivities.

- Include Probabilistic Risk Assessment (PRA) of Aging Transmission System Infrastructure beginning in 4Q, 2006. PRA is employed to mitigate transformer risk on the bulk power system. The consequences of a failure, both reliability and economic impacts, are then considered to implement, when appropriate, a proactive, PJM-wide approach to mitigate operational and market impacts to such failures.

The RTEP will not:

- Include an evaluation of Transmission Owner transmission expansion or enhancement plans for local area load supply, which are not needed for reliability, market efficiency or operational effectiveness of the Transmission System and do not otherwise negatively impact the Transmission System. These Transmission Owner projects (Supplemental Projects) will be identified in the RTEP for information purposes and tracked for possible future impact implications.
- Include any upgrades based solely on scaling up of generation to solve load flow studies for years 6 through 15.

B.3 Procedure

Solicit input and coordinate with Transmission Expansion Advisory Committee (TEAC) and, as appropriate, TEAC's Subregional RTEP Committee.

- Present the preliminary results of the most recent, applicable NERC regional reliability council (ReliabilityFirst and SERC) Reliability Assessments and the most recent PJM Regional Transmission Expansion Plan (RTEP).
- Present a summary of the transmission expansion or enhancement needs that will be addressed in the RTEP.
- Provide periodic updates to the TEAC on status of the RTEP.
- Solicit input on future transmission needs and requirements from those who will not be contacted directly as listed below.
- Schedule and facilitate Subregional RTEP committee reviews as may be needed to foster the goal of a transparent and participatory planning process.

Identify known Transmission System expansion or enhancement needs from the following plans and analysis results:

- Most recent, applicable Reliability Assessments (ReliabilityFirst and SERC) – (on PJM website)
- Most recent PJM Annual Report on Operations – (on PJM website)
- PJM Load Serving Entity (LSE) capacity plans
- Generator and Transmission Interconnection Requests
- Transmission Owner transmission plans
- Interregional transmission plans.

- Firm Transmission Service Requests
- PJM Transmission Expansion Advisory Committee (TEAC) and Subregional RTEP Committee input
- PJM Development of Economic Transmission Enhancements

PJM will consider the RTEP impacts of each Generation Project Developer ("GPD") and/or Transmission Project Developer that is currently engaged in discussion with PJM concerning plans for siting generating and/or transmission facilities.

- Typical items to be included are as follows:
  - GPD and/or Merchant Transmission Facilities developer project status, schedule, and milestones.
  - PJM will review the status of studies currently being performed or scheduled to be performed by PJM for the GPD and/or Merchant Transmission Facilities developer.
- GPD and/or Merchant Transmission Facilities developer plans will be included in the RTEP based on the following criteria:
  - Developer must be presently engaged in discussion with PJM concerning their plans for siting generating and/or transmission facilities and actively pursuing those plans. Interconnection Studies in response to requests for Generator and/or Transmission Interconnections will be conducted in accordance with the following scope:
    - Identify transmission enhancements required to meet reliability requirements over the next 5 years.
    - No studies will be conducted beyond 5 years for interconnection projects.
    - "But-for" costs will be applicable toward all system upgrades identified in the RTEP Baseline.
- GPD and/or Merchant Transmission Facilities developer plans will be treated equal to LSE plans submitted via EIA 411 in that they will be explicitly modeled and explicitly included in the RTEP report.
- GPD and/or Merchant Transmission Facilities developer plans, which have not been released publicly, will be masked to the greatest extent possible to preserve the confidentiality of the developer's identity and specific site location(s).
- GPD and/or Merchant Transmission Facilities developer plans, which were developed as a result of a PJM Phase I System Impact Study or are being developed in conjunction with a PJM Phase I System Impact Study being performed concurrent with the RTEP process, will be evaluated explicitly during the RTEP.
- GPD and/or Merchant Transmission Facilities developer plans which have not undergone a PJM Phase I System Impact Study or are not actively being developed as a result of an agreement executed with PJM to perform a Phase I System Impact Study concurrent with the RTEP process, will only be considered to the extent that the GPD generator installation or Merchant Transmission Facilities developer facility may affect the sensitivity of transmission enhancement or expansion alternatives which are being evaluated.

PJM will exchange information and data with each Transmission Owner (TO) for the purpose of developing RTEP assumptions in preparation for the Subregional RTEP Committee assumptions meeting. Typical items to be included are as follows:

- TOs will verify their transmission and capacity plans.
- TOs and PJM will discuss the status, impact, and schedule of relevant studies in which they are mutually engaged in performing.
- TOs will provide information concerning the contractual rights and obligations which PJM must consider per the RTEP protocol as listed in Schedule 6 of the PJM Operating Agreement.
- TOs will provide PJM with any information related to concerns, operating procedures, or special conditions for each of the TO's systems that PJM should consider related to the analysis to be performed for the RTEP.
- TOs will discuss the accuracy of PJM's load flow representation for each of the TO's systems including the impact of using the present representation for each of the TO's underlying systems.
- TOs will identify system needs which are currently not identified by published transmission plans but could be included for consideration during the RTEP analysis.
- TOs will provide the names, addresses, telephone numbers, FAX number, and email address for personnel identified to interact with PJM on matters dealing with the RTEP process.
- TOs will provide a confidentiality statement regarding all information released to the TO by PJM during the course of the RTEP process.
- TOs will provide information on new loads or changing loads that will impact the transmission plan.

PJM will include available information from neighboring TOs / Regional Transmission Operators, gained in the course of interregional planning activities, related to plans in other regions which may impact the PJM RTEP.

RTEP Analysis General Assumptions:

- PJM System Models will be drawn from the PJM and applicable regional reliability council (ReliabilityFirst and SERC) central planning database which includes transmission plans consistent with the most recent FERC 715 Report and most recent Regional EIA-411 Reports.
- LSE capacity models are to be based on the most recent Regional EIA-411 Reports.
- GPD capacity plans will be modeled as described in Procedures III and IV.
- When the PJM load in the RTEP model exceeds the sum of the available in-service generation plus generation with an executed final agreement, PJM will model new generation to accommodate additional load growth by including generation in Phase III System Impact Study if needed to support the highest forecast load in 15 year horizon.

- PJM Load Forecasts are to be based on the most recent LAS Report.
- Power Flow models for world load, capacity, and topology will be based on the most recent Eastern Reliability Assessment Group (ERAG) power flow base cases.
- Generation outage rates will be based on the most recent generator unavailability data available to PJM. Estimates, based on historical outage rates for similar in-service units, will be used for all generating units in the neighboring regions and for all future PJM units.
- Firm sales to, and firm purchases from, regions external to PJM will be modeled consistent with the provisions for the interchange schedule as outlined in section H.1.2 of Attachment H to this manual.
- Only PJM's share of generation will be modeled to serve PJM load. Generation located within PJM, but not committed to PJM, will be accounted for in the interchange schedule.
- The Reliability Principles and Standards as shown on Attachment D to this Manual 14B, "PJM Reliability Planning Criteria."
- Stability analysis and short circuit studies will also be performed.
- All PJM Transmission System facilities 100 kV and greater, and all tie lines to neighboring systems will be monitored.
- Contingency analysis will include all facilities operated by PJM.
- The published line and transformer daytime thermal ratings at ambient temperatures of 50F (10C) winter, 95F (35C) summer and 59F (15C) light load will be used as the default rating sets for all facilities. PJM will apply alternate Transmission Owner ambient temperature rating sets wherever variations exist.
- The voltage limits applied for planning purposes will be the same as applied in PJM Operations for both normal and single contingency scenarios. For non-single contingency scenarios that are not covered in TO criteria, the voltage limits used in PJM Operations will apply.
- PJM/NYISO PAR Flows: Model 15% of the PJM to NYISO firm interchange, exclusive of merchant transmission facilities, on the Waldwick PARs, 7% on the Goethals and Farragut PARs, and 32% on the Ramapo PARs. In addition, model 80% of RECO load on the Ramapo PARs.
- Assumptions used for the economic analysis and comparison of alternatives will be included in the report.
- Planning and Markets will, annually based on historical data, develop a circulation model to be applied to the 5 year RTEP base case. This assumption will be reviewed with the PJM Planning Committee prior to implementation.

Evaluate Transmission enhancement and expansion alternatives and develop a coordinated Regional Transmission Expansion Plan.

- Develop solution alternatives for regional and subregional transmission needs.
- Evaluate solutions on a regional basis and optimize solutions to address needs on a coordinated regional basis in a single plan.

- Test the single regional plan for reliability, economy, flexibility, and operational performance based on forecasts for future years.

RTEP Deliverables

- A 5-year plan, which includes recommended regional transmission enhancements, including alternatives if applicable, that address the transmission needs for which commitments need to be made in the near term in order to meet scheduled in-service dates.
- The 5-year plan will include planning level cost estimates and construction schedules.
- The 5-year plan will specify the level of budget commitments which must be made in order to meet scheduled in-service dates. The commitment may include facility engineering and design, siting and permitting of facilities, installation or modification of metering system(s) required by Manual 01, or arrangements to construct transmission enhancements or expansions.
- The 15-year plan will identify new transmission construction and right-of-way acquisition requirements to support load growth.

Attachment J contains the checklist for the new equipment energization process to be utilized by Transmission Owners and Designated Entities from inception to energization of upgrade projects.

B.4 Scenario Planning Procedure

Beginning in mid-2006, PJM will include scenario planning evaluations as part of the RTEP process. Scenario planning examines the long-term impacts on the reliability of the PJM system due to uncertainty with respect to certain assumptions implicit in the development of the RTEP. PJM will examine the effects of uncertainty with respect to selected variables such as economic growth effect on the load forecast, circulating transmission flow effects on system deliverability and generation sensitivities. In the course of the RTEP planning cycle scenario planning will evaluate Transmission System requirements, as may be necessary to ensure the robustness of the RTEP. The following sensitivities will be considered:

- Load forecast for economic growth
    - The current 90/10 load values only account for weather uncertainty and do not consider economic growth deviations. An economic growth sensitivity may consider the effects of high economic growth factors and higher than forecast loads to determine the impact on RTEP baseline upgrades identified for years 6 through 10 for:
        - Eastern PJM Mid-Atlantic Region (PSE&G, JCP&L, PECO, Delmarva, AE and RECO).
        - Southwestern PJM Mid-Atlantic Region (PEPCO and BG&E).
        - Western PJM Mid-Atlantic Region (MetEd, PPL, UGI and Penelec).

        - PJM Western Region (ComEd, AEP, Dayton, Duquesne, AP, ATSI, DEOK and EKPC).
        - PJM Southern Region (Dominion).
    - System upgrades identified as required in years 6 through 10 may be advanced if the initiating overload occurs in an earlier year due to the high economic growth factor scenario.
- Circulation
    - Circulation assumptions included in the RTEP baseline analysis will be reviewed for appropriate sensitivities.
- Generation sensitivities
    - When the PJM load in the RTEP model exceeds the sum of the available in-service generation plus generation with an executed final agreement, PJM will model new generation in Phase III System Impact Study to accommodate additional load growth. This newly added generation could affect the load deliverability results either by advancing or mitigating limits. Generation sensitivities may be examined as appropriate to add information regarding the impacts of any such generators with less certain in-service dates. In addition, in areas that are experiencing load deliverability issues, sensitivities to the mitigating effects of new local generation may also be quantified.
    - PJM will analyze the results of any generation sensitivities for consideration of adjustments to any new transmission or ROW acquisition previously identified in the RTEP for years 6 through 15.
- Additional Information
    - For any overloads that resulted in transmission or ROW acquisition in years 6 through 15, PJM will provide the level of new generation or DSM per region that would eliminate the need for the transmission or ROW acquisition.

Attachment C: PJM Deliverability Testing Methods

C.1 Introduction

C.1.1 Purpose of Deliverability Requirements

Schedule 10 of the PJM Reliability Assurance Agreement states that Capacity Resources must be deliverable, consistent with a loss of load expectation as specified by the Reliability Principles and Standards, to the total system load, including portion(s) of the system in the PJM Control Area that may have a capacity deficiency at any time. Certification of deliverability means that the physical capability of the transmission network has been tested by the Office of the Interconnection and found to provide service consistent with the assessment of transfer capability internal to PJM as set forth in the PJM Tariff and, for Capacity Resources owned or contracted for by a Load Serving Entity, that the Load Serving Entity has obtained Network Transmission Service or Firm Point-to-Point Transmission Service to have capacity delivered on a firm basis under specified terms and conditions.

PJM determines the installed capacity requirements for the entire PJM footprint assuming sufficient network transfer capability will exist to ensure deliverability of these resources. In order to satisfy this assumption, the energy from generating facilities that is ultimately committed to meet this capacity requirement must be deliverable within PJM to wherever it is needed.

Deliverability ensures that the transmission system within PJM can be operated within applicable reliability criteria and ensures within those criteria that regional load will receive energy, with no guarantee as to price, from the aggregate of Capacity Resources available to PJM as demonstrated in the applicable planning studies.

C.1.2 Types of Deliverability Requirements

To maintain reliability in a competitive capacity market, Capacity Resources must contribute to the deliverability of energy within PJM in two ways. First, within an area experiencing a localized capacity emergency, or deficiency, energy must be deliverable from the aggregate of the available Capacity Resources to load. This type of deliverability is referred to as load deliverability. Failure of load deliverability tests will result in the initiation of appropriate mitigation actions, including securing additional Capacity Resources or an enhancement to the Transmission System, in order to increase the area’s ability to import power.

Second, Capacity Resources within a given electrical area must, in aggregate, be able to be exported to other areas of PJM. This type of deliverability is referred to as generator deliverability. The generator deliverability test determines whether a generator qualifies for the status of a certified Capacity Resource with respect to the installed capacity obligations imposed under the Reliability Assurance Agreement. It does not guarantee any rights to specific generators to deliver energy to specific loads within PJM. Nor does it guarantee any rights to

generators to produce energy during any particular set of operational circumstances. Failure of the deliverability test for a new Capacity Resource will result in denial of full capacity rights for the generator until such generator deliverability deficiencies are corrected.

These deliverability tests ensure that the PJM Transmission System is adequate for delivery of energy from the aggregate of Capacity Resources to the aggregate of PJM load. PJM has developed comprehensive testing methodologies to verify compliance with each of these deliverability requirements.

C.2 Load Deliverability

C.2.1 Overview of Load Deliverability

C.2.1.1 Purpose of Load Deliverability

The first of these deliverability tests involves confirming that within accepted probabilities the Transmission System can support the delivery of energy from the aggregate of available PJM Capacity Resources to PJM electrical areas experiencing a capacity deficiency. This test is often discussed in the context of demonstrating deliverability to the load as opposed to deliverability of individual generation resources.

To ensure the adequacy of the generating capacity of the entire PJM footprint, the acceptable loss of load expectation (LOLE) is based on load exceeding available capacity, on average, not more than one occurrence in ten years (1/10). This concept of deliverability to load coincides with the assumptions inherent in the determination of the PJM Installed Reserve Margin (IRM), i.e. the total amount of installed capacity necessary to be at the disposal of the PJM operator to ensure delivery of energy to load consistent with an LOLE of 1/10. The determination of the IRM is based on the assumption that the delivery of energy from the aggregate of available Capacity Resources to load within the PJM footprint will not be limited by transmission capability. This assumption depends on the existence of a balance between the distribution of generation throughout PJM and the strength of the Transmission System to deliver energy to portions of PJM experiencing capacity deficiencies.

C.2.1.2 Locational Deliverability Areas

To test the deliverability assumptions inherent in the development of the PJM Installed Reserve Margin, electrically cohesive load areas must first be defined. The historical implementation of this test based these areas on Transmission Owner service territories and larger geographical zones comprised of a number of those service territories. Current study areas also include the definition of smaller areas within service territory boundaries. Twenty-seven Locational Deliverability Areas (LDAs) have thus far been identified including five global LDAs, which are geographical combinations of Transmission Owner service territories, and three sub-LDAs, which are portions of Transmission Owner service territories.

PJM will analyze the need for the addition of an LDA if such a need is identified through either the RTEP market efficiency or other RTEP long-term planning studies. Constrained facilities identified utilizing market efficiency studies that are not resolved by an existing approved RTEP upgrade are identified for further consideration. In addition, future constrained facilities identified utilizing the RTEP long-term planning studies may also result in the need for the addition of a new LDA. These future constrained facilities are screened using thresholds that are included in the RTEP long-term planning studies. This analysis is updated annually based on approved RTEP upgrades. 500 kV and above constrained facilities or other sets of critical facilities that advance more than three years between RTEP cycles are identified for further consideration. If the driver for such constraints advancing more than three years is linked to a specific event (e.g. significant generation retirement), it may require further analysis and the creation of a new LDA.

Once a constrained facility or group of constrained facilities has been identified under these criteria, distribution factor analysis is performed to determine the specific busses to be included in the proposed LDA. The model used to determine the distribution factors will include all approved RTEP upgrades. The specific distribution factor cutoff to be used in the development of a new LDA will be dependent upon an analysis of the specific system topology, generation and load characteristics in the vicinity of the identified constrained facility(s).

C.2.1.3 General Assumptions

C.2.1.3.1 Independent Study Area Generation Capacity Deficiency

For the purposes of analysis, each LDA within PJM is assumed to be experiencing a generation deficiency independently. Thus, the remainder of PJM is assumed to be operating normally and able to supply the study area with emergency power up to the limit of its available reserves. Load in all other PJM areas beyond the area under test will be modeled at 50/50 load level.

C.2.1.3.2 Consistency with PJM Emergency Operations Procedures

In all cases, the study area CETL analysis should reflect actual PJM emergency operations procedures designed to make as much power available to the deficient study area as possible under the prevailing system conditions. This should include but is not limited to

- The operation and redispatch of any available PJM generation external to the LDA regardless of system economics. Redispatch of Capacity Resources are allowed internal to the study area as well to relieve an overload provided that the CETO is increased by the amount of generation reduction required to eliminate the internal overload.
- The activation of any PJM Load Management (LM) schemes within the LDA that may serve to unload limiting facilities to the extent that doing so does not reduce the load in the area under test below the expected 50/50 load.
- The adjustment of any Phase Angle Regulators (PARs) which PJM or PJM member companies control within existing agreements for emergency operation. The PJM/NYISO PAR flows will be set according to Attachment B Section (B.3)(VII)(P).

- The activation of any approved PJM or PJM member company operating procedure. Operating procedures are described in PJM Manual M03 -Transmission Operations.

C.2.1.4 General Procedures

The load deliverability procedures are consistent with the changing nature of load responsibility under wholesale and retail access and provide a wide range of information about the performance of the Transmission System as electrical areas of different sizes are evaluated. The sequence of evaluating areas of differing size involves nesting small sub-areas into larger areas and finally areas into larger geographical areas of PJM to help identify the interrelationships between local and large geographical area deliverability problems.

The specific procedures utilized to test deliverability from the load perspective involve the calculation of both Capacity Emergency Transfer Objectives (CETO) and Capacity Emergency Transfer Limits (CETL) for the various electrical areas of PJM. A CETO value represents the amount of energy that a given area must be able to import in order to meet specified applicable criteria as described in Manual 20A. CETO calculation takes into account all generation within the study area including that which may not be a PJM Capacity Resource. The CETL represents the actual ability of the Transmission System to support deliveries of energy to an electrical area experiencing such a capacity emergency. Provided that the CETL for a given area exceeds the CETO for that area, the test is passed and, on a probabilistic level, the area will be able to import sufficient energy during emergencies. The Transmission System is tested that the transmission risk does not appreciably diminish the overall target of a 1/10 LOLE for PJM.

After an LDA is defined, two generation patterns must be established. The first represents the Capacity Resource deficiency within the LDA. Based on the calculated CETO for the LDA, sufficient resources must be removed from service to create a need to import energy into the LDA. As the magnitude of the deficiency is adjusted, single contingency analysis is used to establish the CETL value. The second generation pattern required represents the dispatch of the remainder of PJM and surrounding non-PJM areas, and is comprised of a much larger number of generators that are not experiencing any emergency conditions. The larger area in PJM is modeled as experiencing only normal levels of unit outages simulated through existing RTEP base case procedures (see also “Deliverability of Generation”).

Both thermal and voltage studies under single contingency conditions are performed at the CETO to determine potential overload conditions and substations with voltage issues. For each LDA, two different dispatches at the CETO import level are examined. The first dispatch is based on a probabilistic approach whereby up to 10,000 different generation outage scenarios within the study area are simulated to create a statistically-based Mean Dispatch Case. The second dispatch uses a combination of discrete generator outages and scaled generator outputs in the LDA to create a Discrete Outage Case.

C.2.2 Current Locational Deliverability Area Definitions

A study area, also referred to as a Locational Deliverability Area (LDA), area may consist of a single PJM transmission owner's transmission system (345 kV and below for the Mid-Atlantic system) with its connected load and generation. The study area may also consist of a portion of such an LDA. In both of these cases, the study area is referred to as a Zonal study area. A study area may also consist of a geographical combination of various transmission systems (with all connected load and generation) sharing common bulk facilities for importing power. Study areas comprised of combinations of Zonal study areas are referred to as Global study areas. Assessment of both Zonal and Global study areas will identify the most restrictive emergency import margins with respect to reliability criteria and deliverability of Capacity Resources to load within the PJM footprint.

PJM Global CETL Study Areas

Eastern Mid-Atlantic Area – Comprises all load and generation connected 500 kV and lower in PECO, PSE&G, JCP&L, Delmarva, AE, and RECO.

Southern Mid-Atlantic Area – Comprises all load and generation connected 500 kV and lower in BG&E and PEPCO.

Western Mid-Atlantic Area – Comprises all load and generation connected 500 kV and lower in Penelec, Met-Ed, PP&L and UGI.

Mid-Atlantic Region – Comprises all load and generation connected 500 kV and lower in Penelec, Met-Ed, PP&L, UGI, BG&E, PEPCO, PECO, PSE&G, JCP&L, Delmarva, AE and RECO.

Western Region – Comprises all load and generation connected 765 kV and lower in ComEd, ATSI, AEP, Dayton, DEOK, Duquesne, AP, OVEC, and EKPC. Note that CPP is within the ATSI transmission Zone.

PJM Zonal CETL Study Areas

Penelec – All load and generation connected at 345 kV and below.

AP – All load and generation connected at 500 kV and below.

ATSI – All load and generation connected at 345 kV and below.

Cleveland – All load and generation connected at 345 kV and below as defined in Figure E-3

DEOK – All load and generation connected at 345kV and below.

EKPC – All load and generation connected at 345 kV and below.

Met-Ed - All load and generation connected at 230 kV and below.

PP&L - All load and generation connected at 230 kV and below.

BG&E - All load and generation connected at 230 kV and below.

PEPCO - All load and generation connected at 230 kV and below.

JCP&L - All load and generation connected at 230 kV and below.

PECO - All load and generation connected at 230 kV and below.

AE - All load and generation connected at 230 kV and below.

PSE&G - All load and generation connected at 345 kV and below.

Delmarva - All load and generation connected at 230 kV and below.

ComEd - All load and generation connected at 765 kV and below.

AEP - All load and generation connected at 765 kV and below.

Dayton - All load and generation connected at 345 kV and below.

Duquesne - All load and generation connected at 345 kV and below.

Dominion – All load and generation connected at 500 kV and below.

Delmarva South - All load and generation connected at 230 kV and below as defined in Figure E-1.

PSE&G North - All load and generation connected at 345 kV and below as defined in Figure E-2.

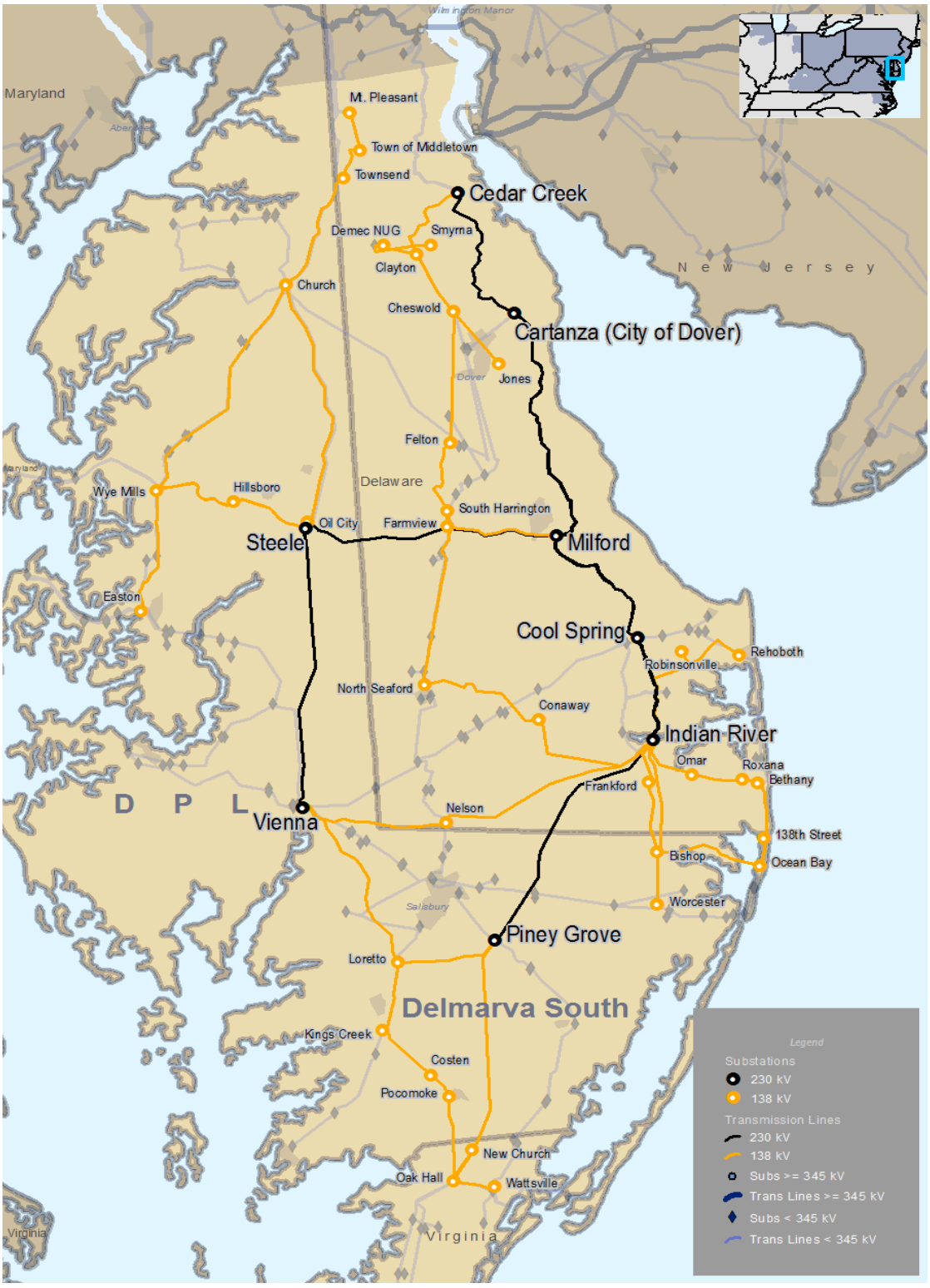

Maryland
M. Pleasant
Town of Middletown
Townsend
Cedar Creek
Demec NUG
Smyrna
Clayton
Church
Cheswold
Cartanza (City of Dover)
Jones
Dover
Felton
Delaware
Wye Mills
Hillsboro
Oil City
Farmview
South Harrington
Steele
Milford
Easton
Cool Spring
Rehoboth
Robinsonville
North Seaford
Conaway
Indian River
Omar
Roxana
Bethany
Frankford
D P L
Vienna
Nelson
138th Street
Bishop
Ocean Bay
Worcester
Salisbury
Piney Grove
Loretto
Delmarva South
Kings Creek
Costen
Pocomoke
New Church
Oak Hall
Wattsville
Virginia
New Jersey
Legend
Substations
230 kV
138 kV
Transmission Lines
230 kV
138 kV
Subs >= 345 kV
Trans Lines >= 345 kV
Subs < 345 kV
Trans Lines < 345 kV

Figure E-1 (Delmarva South)

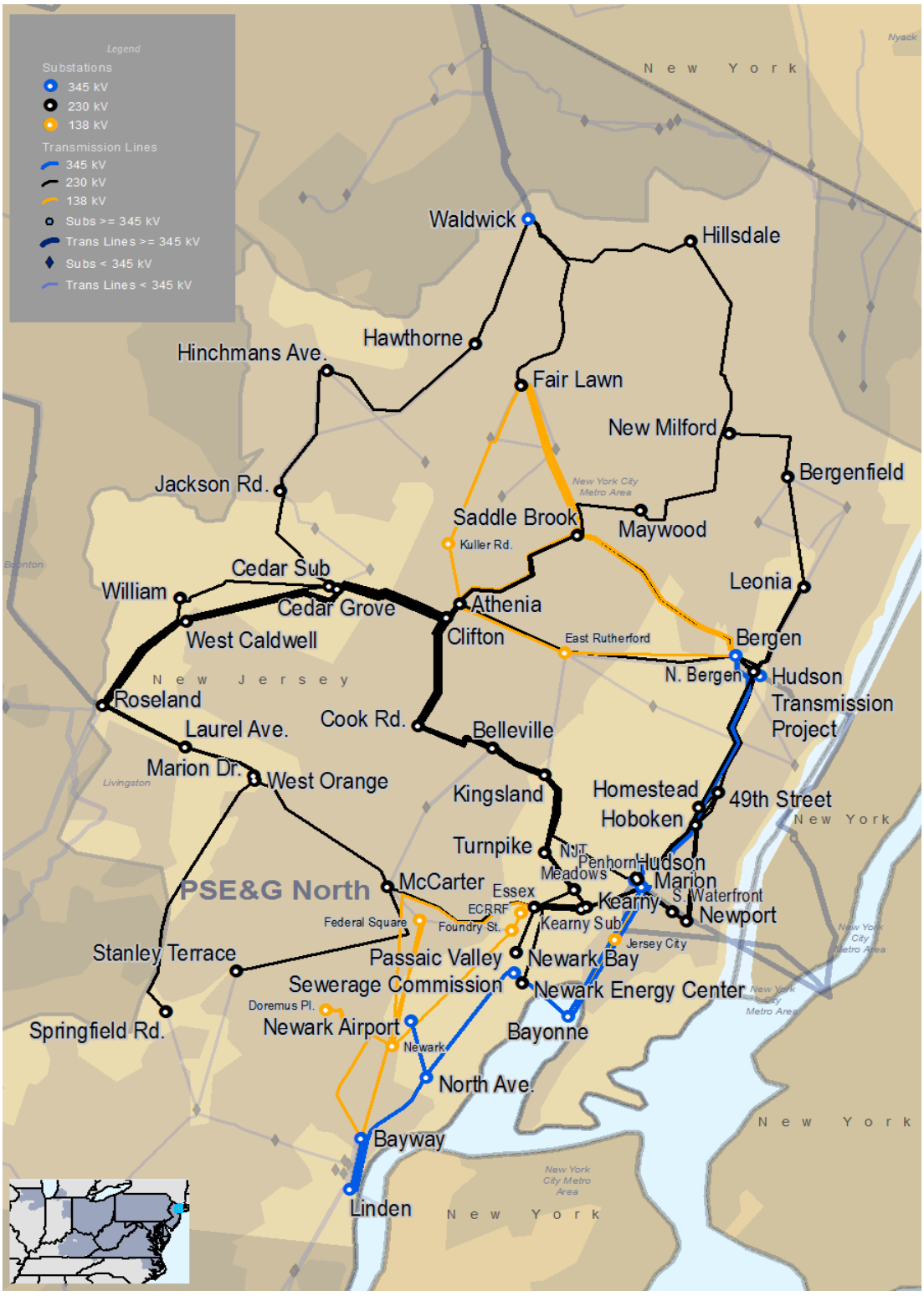

Legend
Substations
345 kV
230 kV
138 kV
Transmission Lines
345 kV
230 kV
138 kV
Subs >= 345 kV
Trans Lines >= 345 kV
Subs < 345 kV
Trans Lines < 345 kV
New York
Nyack
Waldwick
Hillsdale
Hawthorne
Hinchmans Ave.
Fair Lawn
New Milford
Bergenfield
Jackson Rd.
New York City Metro Area
Saddle Brook
Maywood
Kuller Rd.
Boonton
Cedar Sub
William
Cedar Grove
Athenia
Leonia
West Caldwell
Clifton
East Rutherford
Bergen
N. Bergen
Hudson
Transmission
Project
New Jersey
Roseland
Cook Rd.
Belleville
Laurel Ave.
Marion Dr.
Livingston
West Orange
Kingsland
Homestead
49th Street
Hoboken
New York
Turnpike
NJT
Penhorn
Meadows
Hudson
Marion
PSE&G North
McCarter
Essex
Kearny
S. Waterfront
Newport
ECRRF
Federal Square
Foundry St.
Kearny Sub
Jersey City
New York City Metro Area
Stanley Terrace
Passaic Valley
Newark Bay
Sewerage Commission
Newark Energy Center
Doremus Pl.
Springfield Rd.
Newark Airport
Newark
Bayonne
North Ave.
New York
Bayway
New York City Metro Area
Linden
New York

Figure E-2 (PSE&G North)



Figure E-3 (Cleveland LDA)

C.2.3 Base Case Development

Two separate base case models are developed as necessary; a PJM summer peak case to study summer-peaking study areas and a PJM winter peak case to study winter-peaking study areas. The RTEP load flow case nearest to the study time period should be selected and modified as required (modeling the projected load, generation, interchange and transmission system configuration for the target study period).

C.2.3.1 Load Deliverability Area Assumptions

The study area being evaluated is assumed to be experiencing a generation emergency due to a combination of higher-than-expected load demand (a 90/10 load forecast) and greater-than-expected generator unavailability. The 90/10 load forecast level is modeled by using the value of the 90/10load contained in the latest PJM Load Forecast Report along with generator outage scenario(s) that would lead to a generation emergency inside the LDA and thereby potentially cause a transmission import limitation. All Capacity Resources in the LDA are initially modeled online and then generator outage scenarios are developed.

To calculate plausible generator outage scenarios, a file containing the installed MW capacity and the five-year planning equivalent forced outage rate demand (EFORd) for every PJM Capacity Resource will be developed. The EFORds are developed using the Generator Availability Data System (eGADs). Information related to eGADs can be found at http://pjm.com/markets-and-operations/etools/egads.aspx.

Below is a list of additional assumptions that are made when setting up and analyzing the LDA.

- Behind the Meter and energy only generation should be modeled at the average historic MW output during the previous year's 10 highest load hours for the study area each hour being selected from a different day. If this historic information is not available, then these units will be turned off in the power flow model and not included in the load deliverability study.
- Merchant Transmission Facilities, capable of meeting the requirements under the PJM Tariff to obtain Firm Transmission Withdrawal Rights, will be modeled at the greater of their long-term firm transmission service reservation value or Firm Transmission Withdrawal Rights. Refer to Exhibit 4.
- No study areas will be defined with less than a peak load of 1500 MW.
- Generator reactive output will be reduced in proportion to the MW scaling reduction for any generation that is modeled below the rated capability.
- The 90/10 load adder is assumed to be at 0.8 power factor.
- Normal and emergency ratings included in the power flow will be those applied in Operations (at 35C).
- PARs located within PJM may be operated as needed subject to the appropriate agreements (if any) and PJM Operating Company practices. The PJM/NYISO PAR flows will be set according to Attachment B Section (B.3) (VII) (P).
- If the forecast 90/10 MW load minus the available DR (MW) is less than the 50/50 MW load, then the 50/50 MW load will be used in the area being tested. If this situation arises, then the 50/50 MVAR load will need to be adjusted upwards to account for the reduction of the 90/10 MW load to the 50/50 MW load at the same power factor as the 50/50 load instead of at the higher power factor of the 90/10 load, i.e., DR is assumed to have the same power factor as the 50/50 load.

C.2.3.2 Dispatch for Load Deliverability Study Area

Two separate power flow cases are created for each LDA. The Mean Dispatch case models the average value of each generator's output for the LDA under study from over 10,000 unique dispatches at the CETO. The Discrete Outage case models the most likely discrete generator outage pattern within the LDA at the CETO. As described in the CETL determination section, thermal and voltage analysis is performed on both of these power flow cases.

C.2.3.2.1 Dispatch Procedure for Mean Dispatch Case

1. All generators in the study area are sampled until 10,000 generation outage scenarios are found where the amount of generation selected is within +/- 2% of the amount needed to meet the target generator outage value required to model the import objective.
2. The 10,000 generation outage scenarios are determined by using a Monte Carlo simulation and assigning a random value between 1 and 0 to each generator in the study area. If the random value is greater than the generator forced outage rate, then that generator is turned on at its full capability. If the value is less than the generator forced outage rate, then that generator is turned off. There is no limit to the number of units that can be simultaneously outaged at a station.
3. Determine the average MW output of each generator in the study area by using its dispatched values in the 10,000 generator outage scenarios.
4. The reactive capability of each unit is reduced by the ratio of each unit's average MW output from the preceding step to the unit's maximum MW output.
5. Create a base case modeling the average MW output and reactive capability of each generator determined using the above steps.

C.2.3.2.2 Dispatch Procedure for Discrete Outage Case

1. Derate all generators in the zone by their EFORd.
2. Rank generators by EFORd^(1/PMAX).
3. To model discrete generator outages, select generators in rank order until the next selected generator would exceed 105% of the target generator outage value at the CETO.
    a. LDA target generator outage value = LDA UCAP – LDA target generation
    b. LDA UCAP = Sum (1-EFORd)*PMAX for each LDA generator
    c. LDA target generation = LDA load – LDA CETO
4. Multiple generators at the same substation may be taken off line unless the outaged MW to installed MW ratio is greater than 60%. (For example, if a station had 3-100 MW units, 1 unit would be outaged since 100 MW/300 MW = 33% but two units would not be outaged since 200 MW/300 MW = 66%)
5. Any remaining MW outages required to meet the target generator outage value will be obtained through a uniform scale of all on-line generation's MWs and MVARs in the study area.
6. The Transmission Owner(s) may request analysis of a different outage pattern. If this outage pattern results in more severe reliability problems it will be used in place of the original outage pattern only if both the Transmission Owner and PJM accept the new outage pattern.

C.2.3.3 Dispatch for PJM Areas not in a Capacity Emergency

As part of the starting dispatch for PJM Areas not in a Capacity Emergency PJM generators should be dispatched per existing RTEP base case procedures (see also “Deliverability of Generation”).

C.2.3.4 Dispatch for non-PJM Areas not in a Capacity Emergency

One of the base principles for the load deliverability test is that the study area is the only area that is in a capacity emergency. All adjacent external areas to PJM are assumed to be at a peak load but in a non-emergency condition. The PJM firm interchange shall not be adjusted as part of the load deliverability test.

No dispatch or other adjustments will be made to the non-PJM areas to support the PJM area experiencing the capacity emergency.

C.2.4 Capacity Emergency Transfer Objective (CETO) Procedure

The Capacity Emergency Transfer Objective (CETO) analysis determines a target MW import value for an LDA that ensures sufficient transmission capability exists to access available PJM capacity reserves located outside the LDA. The import value determined is a measure of the transmission capability required by the LDA so that the study area does not experience a planned, transmission-induced loss of load event more frequently, on average, than the LDA resource adequacy criteria as described in Manual 20A.

The CETO for each LDA in PJM is determined using PJM’s reliability software to perform a single area reliability study for each LDA. The system models are based on the latest load and capacity data available at the time of the study. Only the load and capacity within the study area are modeled while the capacity supply from outside the study area is assumed to be unlimited. The transmission system is not modeled. The CETO is the import capability value that is necessary for the study area to achieve the CETO reliability standard.

More detail about the CETO is available in PJM Manual 20 – Resource Adequacy Analysis at http://www.pjm.com/library/manuals.aspx

C.2.5 Capacity Emergency Transfer Limit (CETL) Procedure

The goal of a PJM Load Deliverability study is to establish the amount of emergency power, or CETL, that can be reliably transferred to the study area from the remainder of PJM in the event of a generation deficiency within the study area. This transfer limit, in combination with its corresponding CETO, is then used to determine if the import capability required in order to meet the reliability objective is sufficient. An indicator of the amount of reserve transfer capacity available is provided by the difference between the CETL and CETO.

C.2.5.1 Procedure for Determining Load Deliverability Facility List

The following procedures outline the process for determining which facilities will be monitored for the PJM Load Deliverability test. The first procedure provides the details for internal PJM facilities and the second procedure concentrates on external PJM facilities.

C.2.5.1.1 Internal PJM Load Deliverability Facility List

- PJM monitors all internal transmission facilities for its load deliverability test and screens criteria violations for upgrades that pass an outage transfer distribution factor (OTDF) cutoff test and are on PJM's monitored facility list (lists of PJM monitored lines and substations are available at http://www.pjm.com/markets-and-operations/ops-analysis/transmission-facilities.aspx.) The resulting list of facilities constitutes the PJM Load Deliverability Facility List and may vary from study to study because changes in system topology may change the OTDF.
- PJM ensures load deliverability for its entire region by individually studying each LDA. A different subset of the Transmission Facilities is therefore the primary focus for each study area. PJM Transmission Facilities that are not included in the Load Deliverability Facility List are still considered in the load deliverability test. However, they will not be considered as limiting Transmission Facilities for imports into an LDA unless there is also one or more Load Deliverability Facilities simultaneously limiting imports into the LDA, or unless both PJM and the Transmission Owner agree that the facility should be included in the Load Deliverability Facility List regardless of the OTDF.
- The following list of rules defines the OTDF (TDF for pre-contingency violations) cutoff for PJM facilities that will be included in the separate Load Deliverability Facility List for each study area. A TDF is the MW flow over a facility that results from a MW transfer from a source point of all PJM generation external to the study area and a sink point of all load internal to the study area. An OTDF is the TDF after a transmission outage has occurred on the system. Note that if a 100 kV and up facility has a OTDF that is below the OTDF cutoff for each LDA, then that facility will either be addressed in the generator deliverability test or become subject to reliability screening under the standard NERC TPL-001-5.1 criteria[4].
    - All non-radial facilities with a low side voltage 345 kV or greater will be included if their OTDF is greater than or equal to 5%.
    - All non-radial facilities with a low side voltage 345 kV or greater will be included if their OTDF is greater than 2% and less than 5% unless both PJM and the TO agree that the facility should not be included.

[4] Any 100 kV and above facility that is not subject to upgrade screening in the load deliverability analysis will be evaluated in a subsequent screening that evaluates the NERC TPL-001-5.1 criteria in the 50/50 peak load scenario. All facilities failing these standard NERC criteria will be identified for upgrade requirements.

- All non-radial facilities with a low side voltage 345 kV or greater will be not included if their OTDF is less than 2% unless both PJM and the TO agree that the facility should be included.
- All non-radial facilities with a low side below 345 kV with an OTDF greater than 10% will be included.
- All non-radial facilities with a low side below 345 kV with an OTDF between 5% and 10% will be included unless both PJM and the TO agree that the facility should not be included.
- All non-radial facilities with a low side below 345 kV with an OTDF less than 5% will not be included unless both PJM and TO agree that the facility should be included.

- All PJM monitored facilities will be included when determining any generation redispatch or PAR movements required for the base case development. However, only the facilities on the Load Deliverability Facility List will require a system upgrade if overloaded for this load deliverability test.
- The substations to be included for voltage analysis will be developed based on the Load Deliverability Facility List. In other words, the OTDF for a substation will be determined based on the highest OTDF of the transmission facilities directly connected to the substation under the contingency conditions that result in voltage issues. Additional substations will be included for voltage analysis if agreed to by PJM and the TO.

C.2.5.1.2 External PJM Load Deliverability Facility List

For transmission facilities outside of but electrically close to PJM, PJM conducts joint coordinated interregional studies on a periodic basis that examine and address deliverability issues between PJM and adjacent external systems. Based on the results of these joint studies, PJM may choose to include specific non-PJM transmission facilities in the load deliverability test in order to account for significant loop flows that occur through non-PJM transmission systems when large transfers within PJM are present. In order for a non-PJM transmission facility to be included as an External Load Deliverability Facility in either the thermal or voltage load deliverability analysis, it must meet same OTDF cutoff rules that are required for Internal Load Deliverability Facilities.

C.2.5.2 CETL Determination

The CETL for the LDA under study will be the lower of the CETLs identified during the load deliverability studies for thermal and voltage constraints.

C.2.5.2.1 CETL for Thermal Problems

1. Perform an AC contingency thermal analysis on both the Mean Dispatch Case and the Discrete Outage Case to obtain the percent loading on each flowgate for each case at the CETO.
2. If any overloads exist, any of the system adjustments noted in section C.2.1.3.2 can be implemented.

3. Any overloads that still remain will require mitigation in order for the study area CETL to exceed the CETO.
4. If no overloads remain at the CETO import level, then additional transfers into the LDA will be simulated and system adjustments will be applied as necessary. This procedure will be repeated until a transfer level is found (CETL) where one or more transmission facilities on the PJM Load Deliverability Facility list for the LDA under study reaches its applicable thermal limit.
5. The thermal CETL will be the lower of the CETLs determined from the Mean Dispatch and the Discrete Outage Cases

C.2.5.2.2 CETL for Voltage Problems

1. Perform an AC contingency voltage analysis on both the Mean Dispatch Case and the Discrete Outage Case after system adjustments have been implemented to resolve any thermal overloads. Redispatch procedures may be considered to alleviate voltage issues.
2. Any voltage issue that appears at the CETO will require mitigation in order for the study area CETL to exceed the CETO.
3. If no voltage issues exist at the CETO import level, then additional transfers into the LDA will be simulated and system adjustments will be applied as necessary. This procedure will be repeated until a transfer level is found (CETL) where one or more substations on the PJM Load Deliverability Facility list for the LDA under study reaches its applicable voltage limit.
4. The voltage CETL will be the lower of the CETLs determined from the Mean Dispatch and the Discrete Outage Cases.

C.2.6 CETO/CETL as an Input to RPM

PJM follows a similar procedure for the CETO/CETL analysis used as an input to the RPM Base Residual Auction (BRA). This analysis is based on the CETO/CETL analysis used in the RTEP Load Deliverability procedure, but focuses on a 3 year out case. Units without a final GIA or ISA that have cleared in a prior BRA are also included.

In addition to the CETO/CETL analysis performed as an input to the RPM BRA, PJM also determines if there are any easily resolved constraints that could improve the ratio between the CETL and the CETO beyond the threshold of 115%. The process for determining the inclusion of an easily resolved constraint as a transmission upgrade in the RTEP is documented in the PJM OATT (Tariff) in Section 15 of Attachment DD. Criteria needed to be met to include an easily resolved constraint as a transmission upgrade in the RTEP include

- The transmission upgrade(s) will result in a Capacity Emergency Transfer Limit that exceeds 1.15 times the Capacity Emergency Transfer Objective for the LDA; and
- The transmission upgrade(s) is/are expected to be in-service prior to June 1 of the Delivery Year for which the Base Residual Auction is being conducted; and
- The transmission upgrade cost is expected to be less than $5 million; and

- There are no Merchant Network Upgrades that have or are expected to have met all Decision Point II requirements by 45 days prior to the Base Residual Auction that are designed to resolve the same constraint for which the RTEP upgrade is designed to resolve.

The annual costs of such upgrade shall be allocated as specified in Schedule 12 of the tariff.

C.3 Deliverability of Generation

The second deliverability test examines the ability of an electrical area to export Capacity Resources to the remainder of PJM. This test is applied to ensure that capacity is not "bottled" from a reliability perspective. This requires that each electrical area be able to export its capacity, at a minimum, during the summer peak load period as this represents the condition where PJM reserve margins have historically been at their lowest levels. But just demonstrating deliverability in the summer period is not sufficient to ensure operational performance and flexibility is maintained during other part of the year. PJM examines export capabilities under winter and light load conditions as well. All three generator deliverability tests are required to be passed in order for a generator to become certified as a PJM Capacity Resource. Deliverability, from the perspective of individual generator resources, ensures that, under normal system conditions, if Capacity Resources are available and called on, their ability to provide energy to the system will not be limited by the dispatch of other certified Capacity Resources. This test does not guarantee that a given resource will be chosen to produce energy at any given system load condition. Rather, its purpose is to demonstrate that the installed capacity in any electrical area can be run simultaneously, and that the excess energy above load in that electrical area can be exported to the remainder of PJM, subject to the same single contingency testing used when examining deliverability from the load perspective. In addition, common mode outages are examined as part of the generator deliverability test. In short, the test attempts to ensure that bottled capacity conditions that limit the availability and usefulness of certified Capacity Resources to system operators will not exist. In actual operating conditions, energy-only resources may displace Capacity Resources in the economic dispatch that serves load.

This test demonstrates that Capacity Resources in any given electrical area could simultaneously deliver energy to the remainder of PJM. The premise of the generator deliverability test is that all PJM Capacity Resources within an electrical region within PJM are required; hence the remainder of the system outside this electrical region is experiencing a significant reduction in available capacity. The dispatch pattern in the remainder of the system is uniformly reduced according to the relative amounts of online generation at each location.

C.3.1 Generator Deliverability Procedure

C.3.1.1 Introduction

To maintain reliability in a competitive capacity market, resources must contribute to the deliverability within the PJM Control Area in two ways. First, energy must be deliverable, from

the aggregate of resources available to the PJM Control Area to load in portions of the applicable PJM areas experiencing a localized capacity emergency. PJM utilizes the Load Deliverability procedure to ensure this requirement. Second, Capacity Resources within a given electrical area must, in aggregate, be able to be exported to other areas of PJM when required. PJM utilizes the Generator Deliverability procedure to ensure the deliverability of individual generation resources. The following sections describe the Generator Deliverability procedure.

C.3.1.2 Study Objectives

The goal of the PJM Generator Deliverability study is to determine if the aggregate of generators in a given area can be reliably transferred to the remainder of PJM. Any generators requesting interconnection to PJM must be deliverable in order to be a PJM installed Capacity Resource. Addendum 1 to this section describes procedure for modeling Merchant Transmission Facilities in the generator deliverability test. Addendum 2 to this section describes procedures for examining deliverability of any single generating plant up to its maximum facility output and any single Merchant Transmission Facility at its full capability. Addendum 3 to this section describe procedures for evaluating Long Term Firm Transmission Services Requests. Addendum 4 to this section describes gas pipeline contingencies examine as part of the winter test.

C.3.1.3 General Procedures and Assumptions

Step 1: Develop Base Case

The RTEP base case is developed for a reference year 5 years in the future. All identified RTEP Baseline and Supplemental Projects projected to be in service by

- April 15 of the reference year are including in the system model for the Light Load RTEP Base case
- June 1 of the reference year are including in the system model for the Summer RTEP Base case
- December 1 of the reference year are including in the system model for the Winter RTEP Base case

Load is modeled at a non-diversified forecasted 50/50 load level for the period being examined.

- Light Load Period: Those hours between 10AM and 3PM where the PJM coincident peak load is between 40-60% of the annual peak. In the Light Load base case, load levels are modelled at 50% of each area's non-coincident summer peak forecast.
- Summer Period: June through August hours 2PM-6PM
- Winter Period: December through February hours 5AM-9AM and 6PM-10PM

In coordination with individual TOs, PJM will select and apply a Transmission Facility temperature degree ratings set as appropriate. PJM will apply the ratings set on an individual TO basis. The default temperature degree ratings sets are:

- Light Load: 59 °F
- Summer: 95 °F
- Winter: 50 °F, 41 °F or 32 °F

All long-term firm transmission service confirmed for the reference year and service with rollover rights that has been coordinated with the applicable PJM neighboring region is included in the model. Generation and Merchant Transmission Facilities that have proceeded at least through the execution of the final agreement stage of the interconnection process are considered in the model along with any associated network upgrades. If existing Capacity Resources and those with an executed final agreement are not sufficient to meet overall system demand levels then Capacity Resources that have met all Decision Point II requirements may be considered as well.

The starting point dispatch is developed as explained in the next step. PJM uses a block dispatch approach to dispatch the generation and limits the maximum output of any single generator to account for the PJM system-wide forced outage rate and regional weather-related unavailability. This approach to dispatching the generation attempts to broadly account for the economics and operating limitations of individual resource types during the period under examination and avoids direct consideration of any particular resource's confidential economic and operating limitations and the significant bias a less generic dispatch pattern can have on the final overload results.

Step 2: Establish initial RTEP dispatch for unit under study

PJM uses a block dispatch coupled with system wide outage and regional weather considerations to dispatch generation. As shown in Table 1 below, the block dispatch procedure starts with the required generation target to satisfy system wide demand (load, losses and firm interchange) and sequentially dispatches existing units and those with a final agreement in blocks 1, 2 and 3 as needed. If a particular block is only partially needed to meet system demand, then the resources in this block are dispatched as necessary to act as the slack generation and provide constraint control, i.e. certain generators may be dispatched online to relieve base case overloads. Capacity factors used during the block dispatch will be updated and published annually as part of the RTEP assumptions.

In order to ensure that the dispatch does not result in a capacity emergency condition in any of the PJM areas, further redispatch within the area may need to be performed to ensure the area is not importing more than its Capacity Emergency Transfer Objective (CETO). The redispatch methodology will follow the block dispatch approach described above and ensure that the online generation in each area is no less than

- Minimum area generation = (Load + losses – CETO) / (1 – PJM Avg EEFORd)

The denominator in the above equation adds a small margin to the CETO in order to account for the generation ramping that will occur during the actual generator deliverability test. This approach avoids the need to consider the CETO directly in the test itself and helps provide a reasonable starting dispatch for each area. In order to set the minimum area generation, the last block of generation in each area is dispatched to ensure a simultaneous dispatch across PJM where no area is exceeding its CETO plus a small margin and the overall system demand is satisfied. This represents the starting dispatch in the RTEP baseline generator deliverability studies.

Table 1 – Block Dispatch for RTEP Base Cases

Block	Resource Type	Initial Dispatch
1	Nuclear	PMAX * (1 - PJM Avg EEFORd)
	Wind	Capacity Factor
	Solar	Capacity Factor
	Pumped Hydro	PMIN * (1 – PJM Avg EEFORd) LL; PMAX * (1 - PJM Avg EEFORd) Winter & Summer
	Non-Pumped Hydro	PMAX * (1 - PJM Avg EEFORd)
	Other Renewable	PMAX * (1 - PJM Avg EEFORd)
2	Coal	PMAX * (1 - PJM Avg EEFORd)
	Combined Cycle	PMAX * (1 - PJM Avg EEFORd)
3	Simple Cycle	PMAX * (1 - PJM Avg EEFORd)
Note 1: PMAX represents the unit's maximum output for the period. Note 2: Capacity Factor represents the average output for the period. Note 3: In summer, PMAX is replaced with the lower of the Capacity Factor or Capacity Interconnection Rights (CIRs).Note 4: Batteries will be modeled offline but available to be ramped.		

During the generator deliverability evaluation of a New Service Request, additional dispatch procedures are employed. More specifically, all New Service Requests in prior Cycles that are queued ahead of the Cycle under study are available to be turned on. The New Service Request in the Cycle under study is also set at 0 MW but available to be turned on to contribute to but not back off flowgate loadings. New Service Requests in later Cycles that are queued after the Cycle under study are not modeled.

Step 3: Determine potential overloads

PJM uses a linear (DC) power flow program to analyze each facility for which PJM is responsible to determine whether any single or common mode contingency can overload the

facility. These results are utilized to determine which flowgates will be used in the generator deliverability analysis, i.e., the program examines each PJM flowgate (contingency / monitored element pair) in the entire PJM footprint as well flowgates near the border of PJM. The procedure below explains conceptually how the program works; following the procedure below would yield the same results as the program. The procedure uses a load flow set up according to step 2.

Determine the distribution factor for each generator on each flowgate. The distribution factor for a particular generator is referenced to the PJM online generation. For each flowgate, group the Generation Capacity Resources based on whether the distribution factor is positive, in which case increases in the generator's output contribute to the loading on the flowgate and the generator is considered a "Harmer", or negative, in which case increases in the generator's output reduce the loading on the flowgate and the generator is considered a "Helper". Note that the light load test considers pumped storage units in the pumping mode and batteries in both the discharging and charging mode and the appropriate mode to ramp will be based on whether the distribution factor is positive for that mode. For generators with a positive distribution factor on the flowgate, multiply the distribution factor of each generator by the offline portion of the generator to obtain the MW impact the generator would have on a particular flowgate if it were ramped from its output in the initial load flow to its full output. For wind and solar generators with a negative distribution factor on the flowgate, multiply the distribution factor by the online output of the resources to obtain the MW impact the generator would have if it were turned off. This latter step will account for the high variability of the output levels of wind and solar units and the fact that a stressed dispatch should consider lower than average outputs from these resource types. The summation of these MW impacts on the flowgate is the cumulative ramping impact.

For all flowgates determine the cumulative ramping impact of generators with greater than a 1% distribution factor. The total amount of ramped generation as part of this initial identification of potential overloads is capped to limit the number of potential overloads to a reasonable number of the worst impacts. A typical cap for the total ramping of internal generation is 10,000 MW (20,000 MW for studies examining the impacts of external generators as well) but the actual value can vary to establish a reasonable scope for the potential overloads. For each flowgate, add the cumulative ramping impact to the initial DC loading. If the resulting DC loading is greater than the flowgate rating, then this flowgate is a potential overload.

Step 4: Determine Wind and Solar and 50/50 Harmer impacts

The number of generators having greater than a 1% distribution factor in Step 3 is often large enough that having them all simultaneously outputting their full installed capacity or simultaneously be offline in the case of wind and solar would be extremely improbable. As a result, in this step the number of generators contributing to the cumulative ramping impact on a flowgate is further restricted in the following manner.

Dispatch blocks 1 through 3 are available for ramping in the summer and winter testing and wind and solar resources are available for ramping in the light load test. In addition, batteries in

the discharging mode will be considered in light load, summer and winter generator deliverability testing. Also, during the light load condition pumped storage in the pumping mode and batteries in the charging mode will also be considered.

The ramping limit for wind and solar units are applied. For summer, single contingency testing conditions, the ramping level for wind and solar units with a positive distribution factor is restricted to its Capacity Interconnection Rights (CIR). For winter, single contingency testing conditions and summer and winter, common mode outage testing conditions, wind and solar units with a positive distribution factor are restricted to the following regional ramping levels.

- Onshore Wind: P90%
- Offshore Wind: P80%
- Fixed Solar: P80%
- Tracking Solar: P80%

For light load, single contingency and common mode outage testing conditions, wind and solar units with a positive distribution factor are restricted to the following regional ramping levels.

- Onshore Wind: P90%
- Offshore Wind: P80%
- Fixed Solar: Light Load Capacity Factor
- Tracking Solar: Light Load Capacity Factor

These percentiles are used to define the seasonal output levels for the resource type in the region in which it is located as a percent of its maximum facility output for the period under study below which the specified percentage of output levels would occur, e.g. the P90% for onshore wind units in the Mid-Atlantic Region over the summer period is 38% of the MFO. These seasonal output levels are also referred to as the summer deliverability MW, Winter deliverability MW and light load deliverability MW.

For example, onshore wind units will be ramped to a level that is unlikely to be exceeded more than 10% of the time on a wide-area basis. The output levels are based on 10 years of historical or backcast data and are determined by resource type and PJM region (MAAC, PJM West, Dominion) by using the capacity-weighted output level for each area where the resource type is located within the region. The output levels associated with these percentiles will be updated and published annually.

Generation Capacity Resources modeled in the power flow with greater than a 5% distribution factor (or 10% distribution factor for flowgates whose monitored element's lowest terminal voltage level is equal to or greater than 500 kV) that contribute to the cumulative ramping impact are ranked according to their distribution factor on a potentially overloaded flowgate. These are called "Harmer" generators.

Wind and solar units are not assigned an EEFORd because their output levels are based on historical data that inherently accounts for forced outages. For each flowgate, all wind and solar Harmer unit outputs are increased to their ramping levels defined above. The multiplication of the resulting MW output for each wind and solar resource by it DFAX on the flowgate is the wind and solar Harmer impact.

For Generation Resources other than wind and solar resources, the availability (1 – EEFORd) of the unit with the highest distribution factor is then multiplied by the availability of the unit with the second highest distribution factor and so on until the expected availability of the selected units is as close to but not less than 50%. Also, generating plants whose maximum output level is less than 50 MW will not be assigned an EEFORD to help ensure that the impacts of larger units are not masked during this process. This resulting “50/50” cumulative ramping impact is then added to the initial DC loading on the flowgate from the base case dispatch under the specified contingency condition. This resulting loading is the 50/50 DC loading and the generators chosen to contribute to the cumulative ramping impact are the 50/50 generators.

All default ramping limits and Capacity Factors used in the generator deliverability test for all study periods will be updated and published annually.

Step 5: Determine other flowgate impacts

This Step 5 addresses contributions to a flowgate loading beyond those created by the 50/50 dispatch.

- Step 5a addresses offline generators that have a positive distribution factor on the flowgate.
- Step 5b addresses online wind and solar generators that have a negative distribution factor on the flowgate.
- Step 5c addresses interchange considerations.
- Step 5d addresses non-PJM ramping considerations.

Step 5a: Determine Facility Loading Adder

Existing generators which have submitted a request to deactivate, active generators that are in the interconnection queue or Cycle and merchant transmission projects that do not yet have a signed final agreement or have a suspended final agreement may be modeled offline, and, if so, are available to be turned on to contribute to but not back off flowgate loadings. The ramping impact of this set of generators determines the Facility Loading Adder. Facility Loading Adders do not consider offline wind and solar units which are handled separately in Step 4. Further, they are only applied in the summer generator deliverability test where the offline resources will likely be required.

First, for their ramping impact to be considered, off-line generators must pass the impact threshold of at least a 5% DFAX (10% for flowgates with monitored elements having the lowest

terminal voltage 500 kV and above) on a flowgate or with an impact (DFAX times a generator's full energy output rating) greater than 5% of the flowgate's rating.

All studies in Phase I, II and III will use 100% commercial probability.

The ramping impact on a flowgate from each offline resource that meets the above conditions is calculated. These offline resources will be ramped to the same percent output level that other generators of the same resource type are dispatched on average in the case. For example, if the generator is in block 2, and block 2 resources are dispatched at 50% on average, then the resource will be ramped to 50%. Merchant transmission projects will be assigned 100% percent of their firm rights for their output level. The resulting impact defines the Facility Loading Adder.

Step 5b: Account For Lower Than Expected Wind and Solar Outputs

Online wind and solar units with a negative distribution factor are assigned the following lower ramping levels, which are derived in a similar manner to the percentiles developed for wind and solar in Step 4.

- Onshore Wind: P20%
- Offshore Wind: P20%
- Fixed Solar: P20%
- Tracking Solar: P20%

The output levels associated with these percentiles will be updated and published annually.

Step 5c: Interchange Considerations

In order to account for generation assistance from outside PJM in the summer and winter generator deliverability test each receiving end area will be assigned a portion of the PJM Capacity Benefit Margin (CBM) based on the receiving end areas' share of the PJM load. CBM is the amount of import that PJM assumes will be available from neighboring regions during a RTO-wide capacity deficiency.

In the winter and summer generator deliverability test, average historical utilization of PJM firm transmission service is considered to ensure that a range of actual firm usage can be supported. The test examines whether the system can support any combination of firm transmission service between the average historical level up to the full reserved amount.

In the light load generator deliverability test, the average historical interchange levels achieved for this period between PJM and the five external regions defined in the PJM Capacity Import Limit study (see Attachment G.11) and controllable Merchant Transmission Facilities will be examined in addition to the full amount of reserved transmission service.

Step 5d: Account for Non-PJM Ramping Considerations

Under heavy penetration of intermittent resources, it is expected that system dispatches will become more volatile. PJM will incorporate into its generator deliverability test non-PJM dispatch considerations that have resulted in or are expected to result in operational performance issues which hinder the ability of PJM Capacity Resources to deliver their output.

At present, there is a growing penetration of onshore wind in the MISO region that occasionally results in such operational performance concerns on the PJM system. These concerns occur outside of the summer period. As a result, PJM includes ramping of the MISO wind in both the light load and winter generator deliverability testing. The ramping level is the same as that used for onshore wind in the PJM West region in PJM. The sink for the MISO onshore wind ramping is the Northern part of the MISO system.

PJM will periodically assess the need to incorporate other non-PJM dispatch considerations into the generator deliverability test to ensure impacts to the ability of PJM Capacity Resources to deliver their output are appropriately accounted for.

Step 6: Determine Final Flowgate Loading

- The total amount of 50/50 and Facility Loading Adder generation shall not be any more than the online generation × PJM average EEFord. This rule is enforced by curtailing generators that contribute to both the 50/50 list and the Facility Loading Adder. Similarly, the amount of wind and solar generation increased in step 4 to account for higher than expected outputs as well as the amount of wind and solar reduced in Step 5b to account for lower than expected outputs will capped at the same level.

If a flowgate has a final DC loading less than 90% of its rating, it is not considered to be overloaded and is not tested further. If a flowgate has a final DC loading greater than or equal to 90% of its rating, the 50/50 generators are ramped up to their installed capacity in the load flow from step 2 and all remaining PJM generators are uniformly ramped down such that the PJM firm interchange is maintained. The resulting flowgate loading is the 50/50 AC loading.

The Facility Loading Adder can sometimes have a significant impact on the results of a deliverability study. However, ramping up the units associated with the adder in the load flow will sometimes create a localized capacity emergency condition elsewhere when the rest of PJM is proportionally displaced to maintain the firm interchange. Therefore, to account for the effect of these units on the facility in question, the Facility Loading Adder, which is a DC value as determined in Step 5, is added to the 50/50 AC loading to result in the Final Flowgate Loading.

Addendum 1: Modeling Merchant Transmission Facilities (MTFs)

Controllable MTFs, i.e. HVDC which interconnects PJM to another system, may have some combination of firm rights (Transmission Withdrawal Rights, Transmission Injection Rights or long-term firm transmission service). Existing MTFs with firm rights and MTFs with an executed ISA or GIA with firm rights are modeled as a transmission facility carrying the firm rights. Refer to Exhibit 4.

In the case of a bi-directional MTF, the rights associated with the injection into PJM are modeled as an offline generator at the PJM MTF terminal. A net injection from the terminal into PJM equal to the firm injection rights is simulated, consistent with the 50/50 and Facility Loading Adder rules, when such injection contributes to a flowgate's loading.

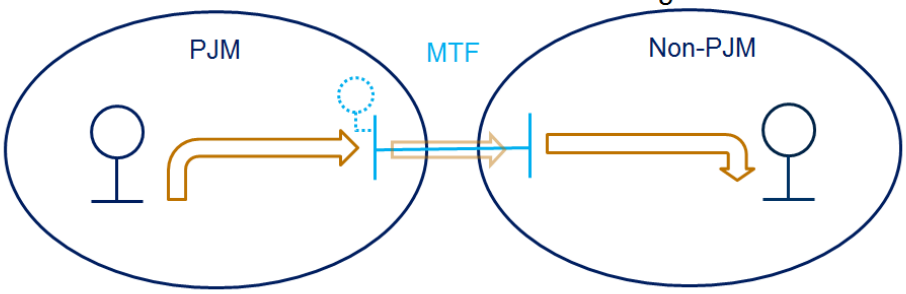
If the MTF request does not have an executed ISA or GIA it will be modeled offline but be allowed to contribute to flowgate loadings consistent with the 50/50 and Facility Loading Adder rules.

Scenario	LTF TS?	Firm TWRs?
1	No	No
2	No	Yes
3	Yes	No
4	Yes	Yes

*LTF TS = Long-term Firm Transmission Service; Firm TWRs = Firm Transmission Withdrawal Rights

Load & Generator Deliverability

- Scenario 1 not considered
- Scenarios 2, 3 & 4 modeled at greater of LTF TS or Firm TWRs
- Firm TIRs modeled as offline generator at MTF PJM terminal in generator deliverability test and able to contribute to but not back off loadings



*Arrows represent firm flows

Common Mode Outage Deliverability

- Scenarios 1 through 4 modeled at FTWRs + NFTWRs
- FTIRs + NFTIRs modeled as offline generator at MTF PJM terminal able to contribute to but not back off loadings

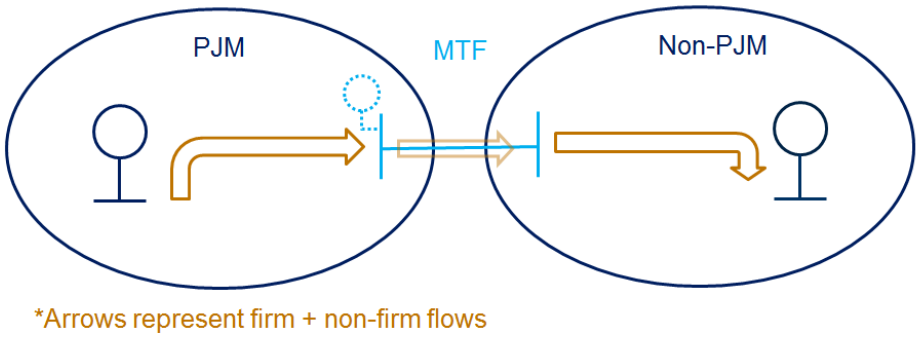


Exhibit 4: Modeling Rights for Merchant Transmission Facilities

Addendum 2: Individual Plant Deliverability Procedure

PJM planning criteria requires that each individual generating plant can be ramped up to its seasonal maximum facility output and each controllable Merchant Transmission Facility can be ramped up to its maximum capability in each direction that it is capable of operating. Under these conditions, the system must be secure for single and common mode contingencies.

Addendum 3: Transmission Service Study Procedures

During the conduct of New Service Request studies, for the evaluation of Transmission Service impacts during generator deliverability testing and common mode outage testing, contribution thresholds have been developed to account for the proximity of the source of the service in relation to the PJM footprint. During testing of transmission service seeking to import energy into PJM, PJM shall use a 3% distribution factor or 3% rating cutoff to select the service which shall be allowed to contribute to flowgates under study. During testing of transmission service seeking to export energy from PJM, PJM shall use these same distribution factor and rating cutoffs to select the service which shall be allowed to contribute to flowgates under study when that flowgate involves a facility outside of PJM's footprint; however, PJM shall maintain all thresholds for impacts to flowgates that involve PJM facilities consistent with the requirements listed outside this Addendum 3.

In both baseline and New Service Request studies, constraints identified in the PJM Capacity Import Limit procedure (Section G.11 PJM Capacity Import Limit Calculation Procedure) are studied in the same manner as internal PJM constraints. With regard to transmission service, in baseline studies any transmission service which impacts a constraint identified in the CIL study

shall have the full impact of the service added to the loading of the applicable facility in determining the final facility loading. In New Service Request studies any transmission service which impacts a constraint identified in the CIL study at greater than the thresholds identified above in this section shall have the full impact of the service added to the loading of the applicable facility in determining the final facility loading.

In both baseline and New Service Request studies, existing import and export reservations which back off overloads will be ramped down to a percentage consistent with the peak historical usage in order to reduce the counter flow for confirmed service to expected levels.

In both baseline and New Service Request studies, PJM shall preserve the Capacity Benefit Margin (CBM) by ensuring that the full amount, specified in the PJM Reliability Assurance Agreement Schedule 4.D, can be imported in addition to the net firm interchange. The distribution of the CBM from each of the five external supply zones shall be determined during the annual PJM Capacity Import Limit (CIL) study, and the CBM impacts will only be considered when they contribute to the loading on a constraint.

Addendum 4: Gas Pipeline Contingencies

PJM will maintain and apply a gas pipeline contingency analysis in winter studies. The gas pipeline contingency set will include gas pipeline contingencies due to the failure of a gas pipeline or a compressor station. The gas pipeline contingency list will be reviewed periodically to validate its accuracy. In addition to the gas pipeline contingencies, gas temperature threshold contingencies will be evaluated. At a pre-determined temperature threshold, assume that non-firm customers (i.e. non-heating demand and 100% of natural gas generation customers in that zone) will be interrupted.

C.4 Long-Term Deliverability Analysis

The purpose of the long-term deliverability analysis is to identify any reliability violations on the PJM system that may require an upgrade that requires more than a 5 year lead time to implement. The PJM RTEP long-term reliability review process examines generator deliverability, load deliverability and common mode outage analysis for years 6 through 15. The long-term analysis starts with the deliverability results from the near-term base case and extrapolates the thermal results using distribution factors and forecast load growth to each year in the long-term planning horizon. If units that have met all Decision Point II requirements are not included in the base case, a second near-term base case will be created to examine whether any long-lead time facilities would be required to support these generators. In addition, a long-term base case is developed from the near-term base case each planning cycle, a limited set of deliverability studies are performed on this long-term base case if the need for long lead time upgrades are identified during extrapolation of the thermal results using the near-term base case, and the deliverability thermal results are extrapolated in a similar manner as is done with the near-term base case in order to produce a second set of long-term results.

C.4.1 Base Case Development

PJM has a 24-month reliability planning cycle. At the beginning of the first year of the cycle, a near-term 5-year out base case and a long-term 8-year out base case are developed. At the beginning of the second year of the cycle, a new 5-year out base case and a long-term 7-year out base case are developed. The same general rules of construction described in section C.3.1.3 of this manual that are used to create the near-term base case are used to create the long-term base case. As a result, the long-term base case is similar to the near-term base case but accounts load growth, generation additions and deactivations, and transmission additions that are forecast to occur between years 5 through 8.

C.4.2 Analysis

The PJM RTEP long-term reliability review process examines generator deliverability, load deliverability and common mode outage analysis for years 6 through 15. The two categories of contingency events considered as part of the long-term studies are single and tower line contingencies. The reason for limiting the long-term review to only these two categories of contingency events is that these events are much more likely than other types of contingency events PJM studies to lead to long-lead-time upgrades.

The deliverability analysis performed on the near-term base case includes a full AC power flow analysis including generator deliverability, load deliverability and common mode outages. The deliverability analysis performed on the long-term base case considers these same tests except that in the load deliverability test, LDAs are selected only if their CETL/CETO ratio was less than 150% in a recent RTEP. Since the objective of the long-term reliability analysis is to identify long-lead-time upgrades, the following types of overloads are not considered.

- overloads on transmission lines below 230 kV
- overloads on transformers
- overloads that are below the conductor rating of the circuit

C.4.3 Linear Extrapolation

The first step of the linear extrapolation of the thermal results is to compile a list of flowgates (monitored facility and contingency pairs) from the near-term and, if required, the long-term base case deliverability results. The calculated base case AC loadings serve as the starting point for the linear extrapolation out through year 15.

Table 1 below is an example of a flowgate that is close to a calculated overload in the near-term analysis that was performed in 2009.

Table 1: Example Flowgate

Electrical Occurrence	Electrical Result	PJM Reliability Test	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Outage of Bedington - Black Oak 500 kV line	Mt. Storm - Doubs 500 kV exceeds its emergency rating and overloads (2016)	Mid-Atlantic Load Deliverability	97.1	98.8	100.5	102.3	104.0	105.9	107.8	109.7	111.6	113.6	115.5

The next step is to determine a factor to increase the loading of the flowgate by for years 6 through 15 to account for load growth. An example of the zonal load forecast by year for selected PJM zones is shown in Table 2. The applicable loads are the forecasted 50/50 load MW values from the PJM Load Forecast Report.

Table 2: Yearly 50/50 Load Forecast by PJM Zone

Company	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
AECO	2,692	2,761	2,980	3,120	3,240	3,301	3,351	3,402	3,448	3,494	3,533	3,572	3,617	3,658	3,687	3,722
AEP	23,682	23,817	24,419	25,109	25,469	25,669	25,897	26,082	26,268	26,426	26,554	26,692	26,804	26,914	27,016	27,097
APS	8,538	8,705	8,949	9,125	9,257	9,378	9,487	9,580	9,683	9,775	9,889	10,038	10,156	10,258	10,375	10,478
BGE	7,303	7,446	7,668	7,764	7,887	8,022	8,176	8,304	8,447	8,586	8,745	8,913	9,050	9,184	9,323	9,483
COMED	22,472	22,803	23,725	24,848	25,552	26,052	26,434	26,766	27,053	27,366	27,722	28,058	28,294	28,468	28,619	28,777
DAY	3,399	3,414	3,552	3,725	3,795	3,825	3,856	3,880	3,909	3,929	3,945	3,961	3,972	3,983	3,991	4,001
DLCO	2,862	2,865	2,915	2,984	3,026	3,065	3,105	3,143	3,185	3,224	3,257	3,292	3,320	3,347	3,375	3,401
DPL	3,972	4,002	4,138	4,289	4,395	4,483	4,554	4,630	4,712	4,789	4,882	4,969	5,059	5,142	5,232	5,317
JCPL	6,357	6,504	6,717	6,931	7,073	7,173	7,269	7,364	7,457	7,541	7,621	7,691	7,763	7,841	7,912	7,983
METED	2,866	2,906	2,995	3,079	3,142	3,182	3,219	3,253	3,284	3,305	3,334	3,364	3,384	3,407	3,424	3,442
PECO	8,455	8,459	8,681	8,893	9,008	9,103	9,212	9,307	9,386	9,467	9,538	9,616	9,678	9,728	9,765	9,806
PENLC	2,786	2,806	2,877	2,949	3,001	3,047	3,098	3,152	3,205	3,252	3,305	3,355	3,401	3,445	3,489	3,529
PEPCO	6,960	7,026	7,141	7,252	7,358	7,437	7,512	7,578	7,657	7,736	7,823	7,911	7,987	8,063	8,140	8,217
PPL	7,106	7,155	7,319	7,494	7,613	7,683	7,757	7,816	7,878	7,932	7,985	8,032	8,066	8,108	8,134	8,170
PS	10,858	11,022	11,292	11,570	11,753	11,885	12,013	12,135	12,257	12,354	12,470	12,572	12,677	12,763	12,859	12,951
RECO	435	441	451	461	467	472	477	482	487	491	496	501	505	509	512	516
UGI	190	191	195	199	201	203	204	205	206	207	207	208	208	209	209	209
VAP	18,982	19,264	19,921	20,675	21,140	21,518	21,895	22,294	22,721	23,130	23,603	24,059	24,506	24,974	25,440	25,929

The yearly forecasted load data is used to determine the yearly load increase by PJM zone. For example, AECO has a forecasted load of 2,761 MW in 2010 and 2,692 MW in 2009. The difference is 69 MW. This value is recorded as the yearly load increase for AECO for 2010. This process is repeated for every year and zone to complete Table 3.

Table 3: Yearly Load Increase by PJM Zone

Company	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
AECO	69	219	140	120	61	50	51	46	46	39	39	45	41	29	35
AEP	135	602	690	360	200	228	185	186	158	128	138	112	110	102	81
APS	167	244	176	132	121	109	93	103	92	114	149	118	102	117	103
BGE	143	222	96	123	135	154	128	143	139	159	168	137	134	139	160
COMED	331	922	1,123	704	500	382	332	287	313	356	336	236	174	151	158
DAY	15	138	173	70	30	31	24	29	20	16	16	11	11	8	10
DLCO	3	50	69	42	39	40	38	42	39	33	35	28	27	28	26
DPL	30	136	151	106	88	71	76	82	77	93	87	90	83	90	85
JCPL	147	213	214	142	100	96	95	93	84	80	70	72	78	71	71
METED	40	89	84	63	40	37	34	31	21	29	30	20	23	17	18
PECO	4	222	212	115	95	109	95	79	81	71	78	62	50	37	41
PENLC	20	71	72	52	46	51	54	53	47	53	50	46	44	44	40
PEPCO	66	115	111	106	79	75	66	79	79	87	88	76	76	77	77
PPL	49	164	175	119	70	74	59	62	54	53	47	34	42	26	36
PS	164	270	278	183	132	128	122	122	97	116	102	105	86	96	92
RECO	6	10	10	6	5	5	5	5	4	5	5	4	4	3	4
UGI	1	4	4	2	2	1	1	1	1	0	1	0	1	0	0
VAP	282	657	754	465	378	377	399	427	409	473	456	447	468	466	489

Load distribution factors are calculated for each flowgate using all online PJM generation as a source and load in each respective zone as a sink. Table 4 contains sample load distribution factors for each PJM zone on the example flowgate involving Mt. Storm – Doubs 500kV. A table of load distribution factors is calculated individually for every flowgate.

Table 4: Area Load DFAX by PJM Zone

Zone	Load DFAX
AECO	0.04591
AEP	-0.03006
APS	0.00818
BGE	0.07542
COMED	-0.02906
DAY	-0.03057
DLCO	-0.0333
DPL	0.04847
JCPL	0.04195
METED	0.04646
PECO	0.04578
PENLC	-0.00404
PEPCO	0.08219
PPL	0.04074
PS	0.04188
RECO	-0.00708
UGI	0.03454
VAP	0.02689

The increase in loading on each flowgate in year 6 is determined by summing the products of the yearly load increases for 2015 and the load DFAX for each zone. This process is repeated for each year through year 15 to determine the final 15 year loading. Table 5 contains an example flowgate that is overloaded in year 7 (2016). The final loading in year 15 (2024) is calculated to be 115.6%. This process is then repeated for every flowgate to complete the system-wide 15 year analysis.

Table 5: Calculated 15 Year Loading of Example Flowgate

Electrical Occurrence	Electrical Result	PJM Reliability Test	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Outage of Bedington - Black Oak 500 kV line	Mt. Storm - Doubs 500 kV exceeds its emergency rating and overloads (2016)	Mid-Atlantic Load Deliverability	97.1	98.8	100.5	102.3	104.0	105.9	107.8	109.7	111.6	113.6	115.6

The linear extrapolation methodology that is performed in the long-term analysis for the remaining years in the planning horizon uses the same methodology described above for the near-term analysis. However, in order to be consistent with this method of matching generation to load growth, the incremental load growth that occurs between the near-term and the long-term case year is assumed to be served by a uniform increase of online PJM generation when creating the long-term base case and when performing the associated long-term CETO calculations.

C.4.4 Long-Term Upgrades

The outcome of the long-term deliverability analysis will identify the need to include in the RTEP any:

- New 230 kV or 345 kV circuits to support load growth in years 6 through 8,
- Right-of-way acquisition for any new 230 kV or 345 kV circuits to support load growth in years 9 and 10,
- New 500 kV or greater circuits to support load growth in years 6 through 12.

Attachment D: PJM Reliability Planning Criteria

The PJM Reliability Planning Criteria consist of multiple standards and applicable planning principles that include PJM planning procedures, NERC Planning Standards, NERC Regional Council planning criteria, and the individual Transmission Owner FERC filed planning criteria. PJM applies all applicable planning criteria when identifying reliability problems and determining the need for system upgrades on the PJM system. Details of specific criteria applicable to the various stages of reliability planning are discussed along with the corresponding discussion of each procedure found elsewhere in this manual.

The PJM Transmission Owners are required to follow NERC and Regional Planning Standards and criteria as well as the Transmission Owner FERC filed criteria. References to the various planning standards and criteria can be found at http://www.pjm.com/planning/planning-criteria.aspx.

- ReliabilityFirst Approved Standards will be applied for all ReliabilityFirst Bulk Electric System facilities.
- SERC Reliability Criteria will be applied to all SERC networked transmission systems rated 100 kV and higher.
- Transmission Owner standards filed in their FERC 715 filings will be applied to all facilities included in the PJM Open Access Transmission Tariff facility list. Also, interconnections to Transmission Owner facilities are subject to owner standards found at: http://www.pjm.com/planning/design-engineering.aspx (these are technical interconnection requirements and do not factor into near-term and long-term planning analyses.

PJM maintains a list (http://www.pjm.com/markets-and-operations/ops-analysis/transmission-facilities.aspx) of all PJM Open Access Transmission Tariff facilities along with which facilities are included in the PJM real-time congestion management control facility list. Both facility lists are referenced in the PJM Reliability Planning Criteria.

The PJM Generator Deliverability Procedure and Load Deliverability Procedure will be applied to all facilities in the PJM real-time congestion management control facility list. These procedures are described in Attachment C.

For all tests, PJM will not accept a loss of load of more than 300 MW, impacting numerous customers. Attachment D-1 contains a description of the various load loss types.

Facilities included in the PJM real-time congestion management control facility list but not included in the applicable regional council planning criteria as defined in section I above will be evaluated against the following criteria. For all tests, PJM will not accept a planned loss of load of more than 300 MW impacting numerous customers. Attachment D-1 contains a description of the various load loss types referred to in this document. This criterion is in addition to, not in place of, each Transmission Owners Planning Criteria as reported in the FERC 715 filing.

- The loss of any single transmission line, cable, generator, or transformer may not result in any monitored facility exceeding the applicable emergency rating or applicable voltage limit. (The applicable emergency rating and voltage limits will be as defined in PJM Operations.) The single contingency test will be applied as per the RTEP Generator Deliverability Procedure. (See Attachment C of this PJM Manual 14B.)
- The RTEP base case which includes a 5-year horizon system representation and non-diversified forecasted 50/50 summer peak load will be used for this analysis.
- System load will be represented at an area or zone wide minimum power factor of 0.97 lagging as measured at the transmission / distribution interface point.
- The 300 MW load limit referenced above does not include load that is immediately restored via automatic switching to adjacent substations. The 300 MW load limit is meant to represent contingencies impacting numerous customers that aggregate to 300 MW or higher.
- Automatic or supervisory switching as proposed by the Transmission Owner to sectionalize the system for single contingency events must receive acceptance by PJM Operations.
- During normal conditions with all facilities initially in-service, no uncontrolled load loss or load loss due to automatic schemes is allowed for a single contingency event. Consequential load loss is allowed.

After the occurrence of the transmission line, cable, generator or transformer outage, the system must be capable of re-adjustment such that no facility exceeds the maximum continuous rating or voltage limits as defined in PJM Operations.

During maintenance of any single transmission line, cable, generator, transformer, bus or circuit breaker, the loss of a transmission line, cable, generator, or transformer may not result in any monitored facility exceeding the applicable emergency rating or voltage limit (The applicable emergency rating and voltage limits will be as defined in PJM Operations.) However, for practical purposes, PJM Planning will only include a specific bus or circuit breaker maintenance condition in all future analysis if PJM Operations experiences operational problems as a result of the bus or circuit breaker maintenance condition.

- Pre-contingency generation redispatch will be considered acceptable for mitigation of a potential overload or voltage limit.
- This test will be applied at 70% of the diversified forecasted 50/50 summer peak load, as modeled in the RTEP base case, unless the Transmission Owner provides information to PJM Operations demonstrating sufficient maintenance windows at a lower load level.

- No cascading or uncontrolled load loss is allowed under any circumstance.
- Consequential load loss is allowed.
- After occurrence of the maintenance outage and the subsequent facility outage as defined in the previous test #3, the system must be capable of re-adjustment such that no facility exceeds the maximum continuous rating or voltage limits as defined in PJM Operations.

The PJM Light Load Reliability Analysis Procedure will be applied to all facilities in the PJM real-time congestion management control facility list.

Attachment D-1: Load Loss Definitions

Uncontrolled Load Loss – Uncontrolled load loss would require operator interaction to prevent system cascading or to return the system to applicable ratings or voltage limits. Manual load dump as defined in PJM Operations would be included in this category. The PJM Reliability Planning Criteria does not allow for the system design to permit Uncontrolled Load Loss for any contingencies that are studied.

Examples:

- Voltage collapse
- A facility overload without automatic schemes to drop load and with no available generation to re-dispatch pre-contingency.

Consequential Load Loss – Consequential load loss occurs due to the design of the system but does not include automatic schemes designed to drop load under various conditions.

Examples:

- A transformer serving radial load that taps a networked circuit.
- Load that is served from a radial circuit.

Controlled Load Loss due to Automatic Schemes – Controlled load loss occurs due to the operation of automatic schemes that are designed to drop load under specific maintenance conditions.

Planned Load Loss = Consequential load loss + Controlled load loss due to automatic schemes.

The 300 MW total load loss limit is based, in part, on a Federal reporting requirement for major system incidents on electric power systems (refer to Electric Power System Emergency Report - Form EIA-417R) impacting numerous customers.

Non-Consequential Load Loss – If situations arise that are beyond the control of PJM that prevent the implementation of a Corrective Action Plan in the required timeframe, then Non-Consequential Load Loss and curtailment of Firm Transmission Service are permitted to correct the situation that would normally not be permitted in Table 1, provided that PJM documents that they are taking actions to resolve the situation. PJM shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

For Table 1 contingency categories that permit non-consequential load loss, PJM will only use this allowance for facilities that become radial after the contingency. Under such conditions,

PJM will not allow any more than 300 MW of non-consequential load loss impacting numerous customers.

Attachment E: Market Efficiency Analysis Economic Benefit / Cost Ratio Threshold Test

PJM uses a Benefit/Cost Ratio test to determine whether an economic-based enhancement or expansion will be included in the RTEP. Specifically, to be included in the RTEP recommended to the PJM Board of Managers for approval, the relative benefits and costs of the economic-based enhancement or expansion must meet a Benefit/Cost Ratio Threshold of at least 1.25:1. The Benefit/Cost Ratio is calculated by dividing the present value of the total annual benefit projected for the 15 year period starting with the RTEP year defined as current year plus 5

minus benefits for years where the enhancement is not yet in service by the present value of the revenue requirement for the same period. Assumptions for determining the present value of the benefits and costs (e.g. discount rate and annual revenue requirement) will be among the assumptions that are considered by the PJM Board each year to be used in the economic planning process.

The Benefit/Cost Ratio is expressed as follows:

Benefit/Cost Ratio = [Present value of the Total Annual Enhancement Benefit for the 15 year period starting with the RTEP Year (defined as current year plus five) minus benefits for years when the project is not yet in-service] ÷ [Present value of the Total Enhancement Cost for the same 15 year period]

The purpose of a Benefit/Cost Ratio Threshold is to hedge against the uncertainty of estimating benefits in the future and to provide a degree of assurance that a project with a 15-year net benefit near zero will not be approved. At the same time the threshold is not so restrictive as to unreasonably limit the economic-based enhancements or expansions that would be eligible for inclusion in the RTEP.

E.1 Total Annual Enhancement Benefit

The benefit component of the Benefit/Cost Ratio (Total Annual Enhancement Benefit) is the sum of two metrics: the “Energy Market Benefit” and the “Reliability Pricing Model (RPM) Benefit.” By including these two metrics, the benefits to customers from reductions in both energy prices and capacity prices as a result of an economic-based enhancement or expansion will be taken into account in the formulaic analysis. This comprehensive test captures customers’ benefits in the energy markets and the capacity markets that may correspond to responsibilities related to obtaining reasonably priced energy as well adequate capacity.

Energy Market Benefit

The energy-market benefit analysis is conducted using an energy market simulation tool that models the hourly least-cost, security-constrained commitment and dispatch of generation over a future annual period. A detailed generation, load, and transmission system model is used as input into the simulation tool in order to mimic the hourly commitment and dispatch of generation to meet load, while recognizing constraints imposed on the economic commitment and dispatch of generation by the physical limitations of the transmission system. Benefits of potential economic-based enhancements, PJM will perform and compare market simulations with and without the proposed enhancement for selected future years within the planning horizon of the RTEP. A comparison of these simulations will identify the annual economic impact of the enhancement for each of the future study years. An extrapolation of these results provides a projection of annual benefits for each of the 15 year period starting with the RTEP year.

The Energy Market Benefit component of the Benefit/Cost Ratio for Regional Projects is expressed as:

inlinescroll*Energy Market Benefit* =

inlinescroll[.50]*[*Change in Total Energy Production Cost*]

inlinescroll+[.50]*[*Change in Load Energy Payment*]

The Energy Market Benefit component of the Benefit/Cost Ratio for Lower Voltage Projects is expressed as:

inlinescroll*Energy Market Benefit* = [1]*[*Change in Load Energy Payment*]

The Change in Total Energy Production Cost is the difference in estimated total annual fuel costs, variable O&M costs, and emissions costs of the dispatched resources in the PJM Region without and with the enhancement or expansion. Costs for purchases from outside of the PJM Region and sales to outside the PJM Region will be captured if appropriate. Purchases will be valued at the Load Weighted LMP and sales will be valued at the Generation Weighted LMP.

The Change in Load Energy Payment is the difference between the annual sum of the hourly estimated zonal load megawatts for each PJM transmission zone multiplied by the hourly estimated zonal Locational Marginal Price for each PJM transmission zone minus the value of Transmission Rights for each PJM transmission zone without and with the economic-based enhancement or expansion. In determining the Change in Load Energy Payments, only zones that show a decrease will be considered in determining the Change in Load Energy Payments.

Reliability Pricing Model Benefit

Reliability pricing benefit analysis is conducted using the Reliability Pricing Model software. The Reliability Pricing Model Benefit component of the Benefit/Cost Ratio evaluates the benefits of a proposed economic-based enhancement or expansion that will be realized in the capacity market and is expressed as:

inlinescroll*Reliability Pricing Benefit for Regional Projects*

inlinescroll = [.50]*[*Change in Total System Capacity Cost*]

inlinescroll+[.50]*[*Change in Load Capacity Payment*]

inlinescroll*Reliability Pricing Benefit for Lower Voltage Projects*

inlinescroll = [1]*[*Change in Load Capacity Payment*]

The Change in Total System Capacity Cost is the difference between the sum of the megawatts that are estimated to be cleared in the Base Residual Auction under PJM's Reliability Pricing Model capacity construct times the prices that are estimated to be contained in the offers for each such cleared megawatt (times the number of days in the study year) without and with the economic-based enhancement or expansion.

The Change in Load Capacity Payment is the sum of the estimated zonal load megawatts in each PJM transmission zone times the estimated Final Zonal Capacity Prices (payments paid by load in each transmission zone) for capacity under the Reliability Pricing Model construct (times the number of days in the study year) minus the value of Capacity Transfer Rights for each PJM transmission zone without and with the economic-based enhancement or expansion. The Change in Load Capacity Payment will be evaluated in the same manner as the Change in Energy Load Payment. Like for the Change in Energy Load Payment, in determining the Change in Load Capacity Payment, only PJM transmission zones that show a decrease will be considered in determining the Change in Load Capacity Payment.

E.2 Total Annual Enhancement Cost

The annual cost of the enhancement is the revenue requirement of the enhancement. The enhancement's annual revenue requirement is an assumption that is developed by PJM and presented to the TEAC for discussion and review. As stated earlier, the benefits and costs will be considered over the same time period, the 15 year period starting with the RTEP year (defined as current year plus 5) minus years where the project is not yet in-service.

Attachment F: Determination of System Operating Limits used for planning the Bulk Electric System

This document describes the process and measures used by PJM to develop System Operating Limits (SOL) and Interconnected Reliability Operating Limits (IROL) used for the planning horizon. In PJM Planning, all BES facilities and "Reliability and Markets" sub-BES facilities, as listed on the PJM Transmission Facilities pages, are considered System Operating Limits (SOL).

Definitions

A System Operating Limit (SOL) is defined as:

The value (such as MW, MVAr, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within applicable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:

- Facility Thermal Ratings (Applicable pre- and post-Contingency equipment or facility ratings)
- Transient Stability Ratings or Limits (Applicable pre- and post-Contingency Stability Limits)
- Voltage Stability Ratings or Limits (Applicable pre- and post-Contingency Voltage Stability)
- System Voltage Ratings or Limits (Applicable pre- and post-Contingency Voltage Limits)

PJM's Planning analyses are designed to ensure all applicable PJM, NERC, regional and Transmission Owner criteria are enforced. This is accomplished through exhaustive application of established PJM facility ratings in the on-going system power flow and short circuit analysis. PJM ensures that its exhaustive application of facility ratings are also within system dynamic limits through system dynamic testing. This dynamic testing confirms that PJM system operating limits are not more limiting than the limits established using facility ratings.

Facility Ratings are defined by NERC as:

- The maximum or minimum voltage, current, frequency or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.

Facility ratings determine the fundamental limits of transmission system equipment. SOLs shall not exceed the facility ratings. The facility rating is based on which ever device or component is the limiting element of the facility such as a conductor, current transformer, disconnect switch, circuit breaker, wave trap or protective relay. PJM plans its system such that no facility exceeds the limit/rating consistent with NERC Standard TPL-001-5.1. Additional information concerning SOL can be found in the Transmission Operations Manual (M-03), and Reliability Coordination Manual (M-37) located on the PJM web page at the following link:

(http://www.pjm.com/-/media/documents/manuals/m37.ashx)

Interconnected Reliability Operating Limits are defined as:

An Interconnected Reliability Operating Limit (IROL) is defined as System Operating Limits that, if violated, could lead to instability, uncontrolled separation or Cascading Outages that adversely impact the reliability of the Bulk Electric System. In the planning horizon PJM analyses examine and reveal the violations of applicable criteria. This includes violations affecting PJM monitored facilities at all voltage levels as well as violations that may have widespread impacts affecting the Bulk Electric System and any lower voltage facilities that are monitored by PJM Operations, which may be eligible for designation as IROLs. PJM plans system upgrades for violations of applicable criteria, thus IROL designations are not typically required for the upgraded system in the planning horizon. PJM closely tracks the project status and milestones of all planned upgrades on a frequent and recurring basis. For baseline reliability upgrades, the project tracking is coordinated with the entity that has been designated the construction responsibility, typically the Transmission Owner. If the schedule for implementation for a planned upgrade does not meet in-service date required for system reliability in the planning or operating horizon, PJM will perform additional analysis to determine any alternative plans that need to be taken to ensure system reliability, including the establishment of an IROL. For additional information on IROLs for the operating horizon see the **PJM Transmission Operation Manual (M03)** and the **PJM Reliability Coordination Manual (M37).**

PJM's Planning methodology to determine IROL facilities simulates transfers across a facility or interface (combination of facilities), comparing thermal and voltage violations associated with a facility. The transfer scenarios used by PJM Planning are established through the application of PJM's deliverability criteria. Additional information on PJM's deliverability criteria is included in Attachment C of this manual. PJM classifies a facility as an IROL facility on the network if wide-area voltage violations occur at transfer levels that are near the Load Dump thermal limit.

As part of the development of the PJM Regional Transmission Expansion plan, SOLs which could result in system instability or uncontrolled cascading outages are identified and system reinforcements are developed. All SOLs are monitored for violations.

SOL and IROL use in Planning

PJM plans its system based on the most restrictive System Operating Limits (such as MW, MVAr, Amperes, Frequency or Volts) of its facilities for the system configurations and contingency conditions that represent the most stringent of the applicable PJM, NERC, regional or Transmission Owner criteria over the planning horizon. The System Operating Limits used to plan the system are consistent with the limits used in Operations. Voltage limits and any exception to those limits are identified in the PJM Transmission Operation Manual (M-03).

An Interconnection Reliability Operating Limit is the value (such as MW, MVAr, Amperes, Frequency or Volts) that is derived from or is a subset of the System Operating Limits, which if exceeded, could expose a widespread area of the Bulk Electric System to instability,

uncontrolled separation(s) or cascading outages. PJM Reliability Coordination Manual (M37) defines PJM's methodology for determining, monitoring, and controlling IROL facilities.

Nuclear Power Plant Generator Operators are required to transmit Nuclear Plant Interface Requirement (NPIR) to transmission entities. The transmission entities are required to include those parameters into planning and operational analysis, operate to meet those parameters, and inform the nuclear licensees when those parameters cannot be met for any reason. For details please refer to Manual M03 Section 3: http://www.pjm.com/~/media/documents/manuals/m03.ashx

PJM Planning SOL Methodology

Consistent with the requirements of NERC Standard TPL-001-5.1 P0, in the pre-contingency state and with all facilities in service, all facilities shall be within their facility ratings and within voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as facility outages.

Following single contingencies as defined in NERC Standard TPL-001-5.1 P1 all facilities should be within their applicable facility ratings and the system shall be transient, dynamic and voltage stable. Cascading outages or uncontrolled separation shall not occur.

Starting with all Facilities in service, the response to a single contingency as defined in NERC Reliability Standard TPL-001-5.1 P1, may include any of the following:

Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the faulted facility. This is often referred to as consequential load loss.

System reconfiguration through manual or automatic control or protection actions.

To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and changes to the transmission system topology.

Starting with all facilities in service and following any of the multiple contingencies identified in NERC Reliability Standard TPL-001-5.1 P2, P3, P4, P5, P6 and P7 the system shall be transient, dynamic and voltage stable and all facilities shall be within their applicable facility ratings and within applicable thermal, voltage and stability limits. Cascading Outages or uncontrolled separation shall not occur. In general, stability is not a limiting constraint in the PJM RTO. Stability limits that have been identified for certain system configurations or following multiple contingencies are identified in the PJM Transmission Operation Manual (M-03). New stability limits identified in Planning are communicated to PJM Operations and included in the Transmission Operation Manual (M-03).

In determining the response to any of the multiple contingencies, identified in NERC Reliability Standard TPL-001-5.1 P2, P3, P4, P5, P6 and P7, in addition to the actions identified above following single contingencies, the following shall be acceptable:

For all tests, as described in Attachment D-1, consequential load loss of up to 300 MW may occur. For those NERC TPL contingencies that permit non-consequential load loss, PJM will allow up to 300 MW of non-consequential load loss for facilities that become radial post-contingency.

PJM's Reliability Planning methodology for determining SOLs utilizes multiple standards and applicable planning procedures including the PJM Reliability Planning Criteria, NERC Planning Standards (TPL-001-5.1), Regional Reliability Organization criteria, and individual Transmission Owner FERC filed criteria. In all cases, PJM applies the most conservative of all applicable planning criteria when identifying reliability problems. PJM tests these criteria on a regional basis including all facilities within its footprint. All SOLs are monitored for thermal, voltage and stability violations. Remediation plans are developed to mitigate the violations that exceed the established SOL limits.

PJM's develops models for specific planning horizons using the latest Eastern Reliability Assessment Group (ERAG formerly MMWG) modeling information available for the applicable planning period. A detailed model is utilized for PJM's internal system (transmission owner under PJM's footprint) while the latest ERAG model for that planning period is used for facilities outside of PJM to incorporate critical modeling details of other control areas. Additional information about PJM's base case development procedures can be found in section 2 of this manual.

PJM reliability planning criteria requires that the system be tested for all BES single contingency outages and all common mode outages. Common mode outages consist of line faults coupled with a stuck breakers that result in multiple facility outages, double circuit towerline outages and bus faults in the PJM system. PJM's planning procedures require all NERC P0, P1, P2, P3, P4, P5, P6 and P7 conditions be tested.

When appropriate PJM will identify and implement Remedial Action Schemes. If the scheme is required for reliability purposes, operational performance, or to restore the system to a reliable state following a significant transmission facility event, operation of the scheme will be tested in the on-going planning analysis. See the Transmission Operations Manual (M-03) (http://www.pjm.com/~/media/documents/manuals/m03.ashx) for additional information concerning Remedial Action Schemes.

The PJM planning process includes a series of detailed analyses to ensure reliability under the most stringent of applicable NERC, PJM or local criteria. Through this process, violations of system operating limits are identified. System reinforcements required to mitigate the violations are developed and included in the Regional Transmission Expansion Plan for implementation. As a result PJM's application of its System Operating Limits for the planning horizon ensures system operation within Interconnection Reliability Operating Limits.

PJM Planning will communicate to PJM Operations any potential IROL facilities resulting from PJM deliverability criteria analysis. PJM Planning and Operations work to develop new IROL Reactive Interfaces and associated operating procedures as required.

Attachment G: PJM Stability, Short Circuit and Special RTEP Practices and Procedures

G.1 Stability

PJM Planning conducts stability studies to ensure that the planned system can withstand NERC criteria disturbances and maintain stable operation throughout the PJM planning horizon.

NERC criteria disturbances are those required by the NERC planning criteria applicable to system normal, single element outage and common-mode multiple element outage conditions. These conditions are specified in the NERC approved Transmission Planning (TPL) Reliability Standards that can be found on the NERC website (www.NERC.com). Because these standards change from time to time they are included here by reference. In addition, PJM's analyses also satisfy the Transmission Owner specific stability practices and procedures as may be applicable when these are more demanding tests than the standard NERC criteria tests applied by PJM. All Transmission Owner specific information and criteria that exceed *standard testing of NERC criteria* and are applicable to PJM reliability based RTEP stability analyses are included or referenced in the Appendix to this Attachment. Transmission Owner stability criteria filed as FERC Form No. 715 and posted on PJM's website and not included in the Appendix may be used to support Transmission Owner funded upgrades. The currently approved version of this Appendix at the commencement of the RTEP process will be the basis for that baseline RTEP and related generator Cycle assessments. PJM's stability analyses verify satisfactory projected system performance over the range of anticipated load levels and identify any need for upgrades, operating guides, or Remedial Action Schemes that may be indicated based on stability or short circuit testing as a primary driver. In general, the most appropriate remedy to NERC criteria violations is a system upgrade. In circumstances involving criteria that go beyond PJM's standard testing of NERC criteria, operating guides or Remedial Action Scheme remedies may also be considered as discussed further in this Attachment and its Appendix. New Remedial Action Schemes, however are generally avoided and, if considered, require case-by-case review and justification. Also certain specific areas of PJM have been identified through PJM or Transmission Owner analysis as stability limited areas of the system. In such areas of the system, stability operating guides may apply. For related information see PJM Manual 03 at http://www.pjm.com/library/manuals.aspx.

Critical system conditions for stability analysis on the PJM system are generally characterized by light load and peak load. System peak load levels shall include a load model where applicable which represents the expected dynamic behavior of loads that could impact the study area, considering the behavior of induction motor loads. An aggregate system load model which represents the overall dynamic behavior of the load is also acceptable where applicable. In exceptional cases, PJM may add alternate load testing when PJM determines that an alternate load level may be the critical load level for system stability for the limitation under review. Peak

load stability analysis related to new interconnections of wind turbines and their low voltage ride through performance will also be performed.

System conditions most critical for stability analysis on the PJM system are generally characterized by light load. Peak load analysis is added for stability reviews that involve new connections of wind turbines and performance of low voltage ride through testing. In exceptional cases, PJM may add heavy load testing for other types of units when PJM determines that heavy load may be the critical load level for system stability for the limitation under review.

PJM's stability analyses ensure the dual objectives of stability of new interconnection projects and system-wide stability. PJM conducts New Service Request stability studies. These analyses ensure newly connecting projects and nearby changes to the system configuration maintain the stability of the project and the system. Study of these projects located throughout PJM provides a thorough, ongoing review of PJM both at the project level and system-wide. In addition, each year, PJM conducts a re-study of one third of existing PJM generation stations. This results in a three-year cycle of on-going re-study of the entire PJM system. PJM also performs additional system-wide stability analyses during the annual RTEP review. In addition, as may be required from time to time, PJM conducts stability analyses to evaluate the dynamic performance of actual or possible major future system developments. For example a proposed new backbone transmission project or prolonged unexpected backbone transmission outage in a stability sensitive area would be cause for a specifically targeted system study. Another cause could be the need to evaluate system performance resulting from major developments affecting power and energy policy.

G.2 Dynamics Procedures

This section provides a high level review of the process of setting up and performing dynamics analyses.

G.2.1 Dynamics Reference Cases

Reference power flow cases for stability analysis are created in a similar manner to that of the power flow reference cases. Additional information, however, is necessary for stability studies to simulate the combined dynamic responses of various power system components. Included in this additional information are dynamics models for generators, excitation systems, power system stabilizers, governors, loads and various other equipment. The required dynamic and other modeling information that must be supplied by generators interconnecting to the PJM system is detailed in Manual 14H. A dynamic simulation links the system model or power flow information with the dynamic data or models to determine if the system and generators will remain stable for steady-state and various disturbances. The current RTEP summer peak case is used as a starting point to create new dynamics cases (light load and peak load.) For example the RTEP analysis is performed for the current year plus five (available early in each calendar year and updated for the five-year-out RTEP analyses in early fall of each calendar year). The stability case setup is for the same study year using the updated RTEP case. This

updated RTEP power flow case and the associated stability case become the baseline cases for the Phase II System Impact Studies that evaluate New Service Requests. In the event that stability analysis is needed beyond the Near-Term, the Long-Term Transmission Planning Horizon portion of the stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies and shall include documentation to support the technical rationale for determining material changes.

G.2.2 Dynamics Analysis

The two dynamics cases Originate from the RTEP Power Flow Case that is created for the annual RTEP Plan analyses. The RTEP cycle is depicted in Manual 14B, Exhibit 1. The reference power flow case is reviewed and modified as necessary to correspond to the dynamics database (which includes external world dynamics data from the Eastern Interconnection Reliability Assessment group's Multi-Regional Modeling Working Group as well as PJM data.) In addition, the case is modified to include generator step-up transformers and explicit modeling of generator station service power use along with gross generator rating. Also, because of the demands of dynamics analyses, constant power load representations in the power flow case are replaced with Transmission Owner provided load model representations. In light load representations, pumped storage resources are in pumping mode.

This process is followed to develop stability setups for analysis of all PJM interconnection requests. In addition PJM's system stability analyses will use the most current available setup from this continuous development process.

Testing

After the dynamics model setup, dynamic case initialization and acceptance test are conducted. After case verification, the final, initialized set of power flows and the associated snap-shots, along with the associated dynamic run files are available upon request to Project Developers and others who have a legitimate need for the information, subject to applicable Confidentiality and Critical Energy Infrastructure Information processes (see PJM Operating Agreement §18.17 and http://www.pjm.com/library/request-access/form-ceii-request.aspx.

Dispatch

The assumptions used for generation dispatch can be critical to the results. It is generally accepted that units operating at their highest possible power output and generating as little reactive power as necessary to maintain voltages are likely to be less stable. Normally, and to the extent where no resulting thermal overloads occur under system normal and N-1 contingency conditions, the units in the vicinity of the project under study as well as the study unit(s) will be turned on to their maximum real power output with unity power factor at the high side of the GSUs, or units' VAR output will be adjusted to hold scheduled voltages, depending on specific Transmission Owner criteria. Wind facilities are tested at light load for stability and peak load for low voltage ride through at 100% of their maximum energy value. In addition,

stability test scenarios necessitated by any applicable Transmission Owner operating guides will also factor into each analysis.

Simulations to determine required upgrades (also see the Appendix to this Attachment)

Fault Criteria:

- Fault Types: For interconnection and system stability analyses, three phase faults, single line to ground faults with stuck breaker and single line to ground faults with the communications failure cleared within zone 2 time will be examined. Each analysis will include a determination of the most critical faults to apply. Planning events expected to produce more severe impacts shall be identified. A list of these contingencies as well as the rationale for selection shall be available as supporting information.
- Clearing Times: Dynamic simulation issues are identified using estimates of actual (nominal) clearing times, including relay trip times, breaker interrupting time, fault extinguishing time, intentional delay time, and a margin for error.
- Reclosing: Only high speed reclosing (less than one second) is modeled if present. Successful high speed reclosing and unsuccessful high speed reclosing into a fault where high speed reclosing is utilized will be examined.
- Fault locations: For interconnection analysis, see section G.3.2 New Service Request Stability Study Procedure. For system analyses, the scope will determine the most critical locations to apply criteria faults.
- Maintenance outages: Interconnection analyses of planned line maintenance outage conditions prior to fault application are system conditions that can be anticipated and that are generally of limited duration. The least cost remedy to issues during such system conditions is to require generation to curtail output. Such analyses are, therefore, of primary interest in the operating horizon and are not generally considered to determine upgrade facilities required prior to interconnection. Nevertheless, prior to commercial operation, or prior to completion of the Phase II System Impact Study at the request of the Project Developer, Planning will screen critical faults for issues during line maintenance. The results of the line maintenance study will be conveyed to PJM Operations, the Project Developer and affected Transmission Owners.
- PJM addresses Power System Stabilizer (PSS) outages in a similar fashion. If there are existing PSS installations nearby a new interconnection or if PSS is required on the new interconnection, critical faults for the outage of these devices will be studied prior to commercial operation and the results will be conveyed to PJM Operations, the Project Developer, and affected Transmission Owners.
- Tripping of transmission lines and transformers where transient swings cause protection system operation shall be analyzed using generic relay models.
- For NERC Transmission Planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not results in the tripping of any transmission system elements other than the generating unit and

directly connected facilities. Directly connected facilities for this requirement are facilities intended to or designed to trip as a consequence of the out-of-step event.

Margins:

The margins applied by PJM are intended to be applied in System Impact Study stability analysis that uses a project's final stability study data as further discussed below. As such, these margins account primarily for uncertainty in actual clearing times, and the final data represents the "as built" performance. With the machine modeled at net unity power factor at the high-side of the GSU (or unity power factor at the generator terminals for wind turbine installations), transient stability must be maintained for tested faults when the following margins are included:

- Add 0.25 cycles to the nominal primary clearing time for 3 phase, normally cleared faults.
- Add 0.25 cycles to the nominal primary clearing time for single-line-to-ground faults, plus an additional 0.5 cycles added to the nominal backup clearing time for stuck breaker (.75 cycle total clearing time margin).
- Add 0.25 cycles to the nominal primary clearing time for single-line-to-ground faults, plus an additional 1.25 cycles to the nominal Zone 2 clearing time for failure of primary relaying (1.5 cycle total clearing time margin).

Monitoring requirements:

Rotor angle, real/reactive power output, EFD, speed and terminal voltage of units under study are monitored. Bus Voltages in the same area are also monitored.

Acceptable Transient Voltage Recovery

When a fault occurs on the transmission system, system voltages are temporarily reduced. Once the fault is cleared, voltages follow transient voltage recovery trajectories governed by system dynamics.

The transient voltage recovery criteria should be satisfied at BES buses.

Regardless of the load model that is selected, the voltage following fault clearing shall recover to a minimum of 0.7 p.u. after 2.5 seconds. If a plant-specific document (such as NPIR) or local Transmission Owner specific planning criteria requires a more conservative voltage recovery criterion that specific criterion will be applied. More conservative limits may be agreed upon by PJM and the TO.

Acceptable Damping:

Following the disturbance, the oscillations of the monitored parameters display positive damping. The positive damping is determined with a damping coefficient calculation algorithm. This characterizes the degree of positive (damped) or negative (undamped) damping based on

the damping trend, over the duration of the stability run, of the envelope of machine angle oscillation peaks. This trend can be observed by drawing an envelope connecting each succeeding peak or valley of the oscillation of the monitored element. An acceptable oscillation envelope will demonstrate a positive decay within the appropriate test period (normally 10 to 15 seconds). A sustained oscillatory system response, even if slightly damped, will cause the system to be in a vulnerable state and exposed to adverse impacts for subsequent changes to the system over some prolonged time. To limit this system exposure PJM uses a 3% damping margin. Such positive damping demonstrates an acceptable response by the system, and no further analysis is required. Failure to meet the damping standard will require application of some combination of power system stabilizers, excitation system upgrade and tuning, and system upgrade.

G.3 New Service Request Stability Study Procedures

PJM performs New Service Request stability analysis as a part of the Phase II System Impact Study. PJM's standards for stability analyses satisfy NERC criteria and are the generally applicable criteria for all PJM stability analyses. In addition, Transmission Owner stability criteria may apply. PJM or Transmission Owner analysis have identified certain specific areas of PJM as stability limited areas of the system. In such areas, stability operating guides may apply. See PJM Manual 03 at http://www.pjm.com/-/media/documents/manuals/m03.ashx for more information on PJM stability operating guides.

G.3.1 New Service Requests Stability Data Requirements

PJM Manual 14H details data submission requirements for each phase of the Cycle process.

G.3.2 New Service Request Stability Procedure

This section outlines the process of coordination and execution of the stability study among the representatives of PJM, the Project Developers and Transmission Owners during a Cycle. These procedures apply to stability studies required as part of the New Service Requests process. These stability studies identify needed reinforcements and determine cost responsibility for these reinforcements due to New Service Requests stability issues. The upgrade responsibilities become part of the Generation Interconnection Agreement (GIA).

During Phase I, all verified and accepted Dynamic Models submitted by each Project Developer will be added to the selected dynamics basecase (light load, and/or summer peak load) being used for that Cycle. The New Service Requests in that Cycle will be grouped into clusters based on a clustering methodology. Once the clusters are identified, the New Service Request will remain in that cluster until the end of the Cycle, or until the New Service Request withdraws or is terminated. A scope of work will be developed for each cluster of projects, which will include, but not be limited to the following items:

1. A list of the projects included in the cluster along with a brief description of each project's POI location, MW size and other relevant information. The stability evaluation is performed at the maximum MW output specified for the project.
2. A detailed fault list to test NERC, PJM and Transmission Owner criteria faults, as applicable. The fault specification list will include:
    a. Fault location
    b. Phase involvement
    c. Fault Impedance
    d. Clearing times and reclosing, if applicable
    e. Explicit timing or other margins to be added
    f. Justification of any procedures that exceed PJM standard methods

At a minimum, faults will be developed at the POI bus and one bus away from that bus. In addition, other fault locations judged by PJM as critical to cluster response will be added to the scope.

1. For areas in the cluster affected by established operating guides or Remedial Action Schemes (RAS), as noted in Manual 03, scenarios designed to test the proper operation of the existing guides or RAS may be included, as deemed necessary by PJM. In such cases, the scope will be augmented to examine and specify modified procedures or facilities that ensure the integrity of the system operation.
2. All special study conditions, scenarios or simulations, if any, required by guides or sensitive areas and specific clearing times.
3. A table listing the generating units that will be dispatched for the cluster stability study.

The affected Transmission Owner(s) will have five business days to review the scope of work developed, and provide comments/input to PJM representatives if any additional specific scenarios should be considered. The finalized scope of work will be used for the stability study in Phase II.

During Phase II, changes from Decision Point I will be incorporated into the dynamics basecase, the stability clusters and scope of work, as needed. Contingencies for the faults in each cluster are created. The stability study is run based on the scope of work developed for the cluster. If any issues are identified in the stability results, the Transmission Owner will provide upgrades to mitigate the instability, along with cost and time estimates. PJM will review and test the

upgrades to verify it resolves the issues identified. Cost allocation will be done in accordance with M14H Att 02. The completed stability study report and results are sent to the affected Transmission Owner(s) to review. Upon completion of the Transmission Owner review PJM will issue the final Phase II System Impact study report to the project developer.

In situations when the required system modifications or upgrades cannot be accomplished by the projected in-service date of the project, PJM will develop a scope and schedule to determine interim solutions and dates along with provided interim capability.

During Phase III, changes from Decision Point II will be incorporated into the dynamics basecase as needed, and if a restudy for a cluster is required, it will be performed during Phase III. The process to restudy and finalize the stability study results is the same as outlined in Phase II above.

Changes during Decision Point III will be incorporated on an as needed basis for each cluster.

G.4 System Stability Studies

In addition to the stability analyses of new generating interconnections, the three year cycle testing of all existing generating units interconnected to the PJM system, and certain “ad hoc” stability testing required by special circumstances that occur from time to time, PJM also conducts system stability testing of its most critical stressed system conditions during the annual Regional Transmission Expansion Plan study cycle. The RTEP stability testing examines and ensures system performance within criteria for heavy system transfer conditions. Power flow criteria are ensured on a local and system-wide basis for heavy transfers during the application of PJM’s load deliverability testing (see Manual 14B Attachment C.) These test scenarios examine emergency conditions involving extreme generating outages and loads coupled with single transmission element outages. Such circumstances are critical when the system is stressed at heavy load, rather than light load.

Based on the results of each annual RTEP cycle and previously completed stability analyses, PJM determines the load delivery limits for the case that represents the most critical conditions for PJM system stability testing. The transfers into the selected Region emanate from external PJM and non-PJM generation. Imports from external areas are based on historical levels for heavy load. An example of the type of PJM scenario that could represent the critical study condition may have local load of 65,000 MW with a transfer into the area caused by the simultaneous outage about 10,000 MW of internal area generation. This may cause a thermal limit to transfers well in excess of 6000 MW.

The transmission outage that sets the limit for transfers during the Mid-Atlantic load delivery testing is modeled for stability to ensure that the region is not stability limited. PJM also determines several more critical three-phase and single-line-to-ground fault tests to apply from a stability perspective to ensure robust, stable and adequately damped system performance. Fault testing for system stability includes the most critical Bulk Electric System lines.

G.4.1 NERC P3 and P6 "N-1-1" System Stability Studies

INTRODUCTION

An N-1-1 contingency pair is defined as a single line to ground (SLG) or 3-phase fault with normal clearing, manual system adjustments, followed by another SLG or 3-phase fault with normal clearing. In the NERC TPL standard, N-1-1 contingencies belong to P3 and P6. Manual adjustments after first (N-1) contingency are allowed to relieve any thermal or voltage violations for applicable ratings and/or to prepare for second (N-1-1) contingency.N-1-1 stability analysis is defined as a stability analysis for given N-1-1 contingency scenarios. For a given N-1-1 contingency scenario, the first (N-1) contingency is applied to a pre-disturbance base case. If the system is stable, a new operating point is computed and manual adjustments are made if necessary, and then stability is monitored following second (N-1-1) single contingency. Because of the assumed long time delay (from a stability point of view) between two single contingencies, the N-1-1 stability analysis is similar to maintenance outage study for operational guidelines.

DISPATCH

Initial base case creation for N-1-1 stability analysis follows the procedure in Attachment G, section 2.2. When an N-1 base case is created, care needs to be taken before an N-1-1 contingency is applied. First, all thermal or voltage violations in the N-1 base case should be resolved through system adjustment. Second, if available, any existing operating guidelines for the N-1 outage condition needs to be applied to the N-1 base case.

N-1-1 STABILITY ANALYSIS PROCEDURE

Considering the number of generating machines in the PJM system and the number of possible N-1-1 contingency pairs, it is very challenging to cover all of them within a reasonable lead time. In general testing all N-1-1 contingency pairs for stability is impractical and not necessary due to the fact that most contingency pairs are electrically far away from a study plant or independent from each other. It is essential to screen out critical contingency pairs which have potential stability problems without missing any potentially unstable N-1-1 contingency pairs.

Overall procedure of N-1-1 stability analysis for generating units in PJM area is as follows:

- Selection of plants for the N-1-1 stability study
  - The scope of annually studied plants will include the same plants included in the scope of the baseline stability study that year. Similar to the baseline stability study, one third of generators in PJM will be considered for the N-1-1 stability analysis each year resulting in every PJM generator being studied at least once every three years.
  - If PJM Transmission Planning determines that the scope cannot be completed within a reasonable lead time, PJM Transmission Planning will prioritize the plants in the scope of the study and higher priority plants will be studied first.
  - With the request of PJM Operation or Transmission Owners due to special operation need, the study for specific plants would be performed.

- Selection of N-1-1 contingency pairs for each plant.
  - N-1-1 contingency pairs within one bus from the high tension bus of the study plant are tested. If the number of branches connected to the high tension bus is less than three, the boundary of N-1-1 contingency pairs is extended to two buses away.
- Conduct N-1-1 stability study
  - Assume N-1 stability results are available from the baseline stability analysis.
  - If an N-1contingency is transient unstable, the N-1 stability issue must be resolved first. For each N-1-1 contingency pair, create an N-1 base case by solving a power flow after the N-1 contingency is applied to the N-0 base case. If there are any thermal or voltage violations, resolve them through system adjustments. Also if available, apply existing operating guidelines for the N-1 outage condition to the N-1 base case.
  - Conduct comprehensive time-domain simulation for the N-1-1 contingency and assess stability.
    - Following standard PJM stability criteria, both transient stability and damping will be monitored
  - Consider RASs or other specific operating guidelines.

STUDY PLANTS SELECTION

The factors taken into account in prioritizing plants include the size of a plant, N-1 baseline stability study results, plant fuel type, and the unavailability rate of neighboring branches of the study plant. The following plants are given the highest priority for the N-1-1 stability study.

- Nuclear plants take the highest priority and will be studied if they are in the scope of the annual baseline stability study
- Plants with the maximum output of 1000 MW or above.
- Plants having weak stability performance in baseline stability study.
- Plants that experienced operational stability issues in real-time.
- Plants having neighboring branches with high unavailability rate due to planned and/or unplanned outages.

N-1-1 CONTINGENCY SELECTION

Due to the number of combinations of N-1-1 contingencies, only single contingencies that are 1-bus away from the high-tension buses of the study plant are considered. In the example below, five single transmission line outages are considered in the N-1-1 stability study as shown in Fig. 1.

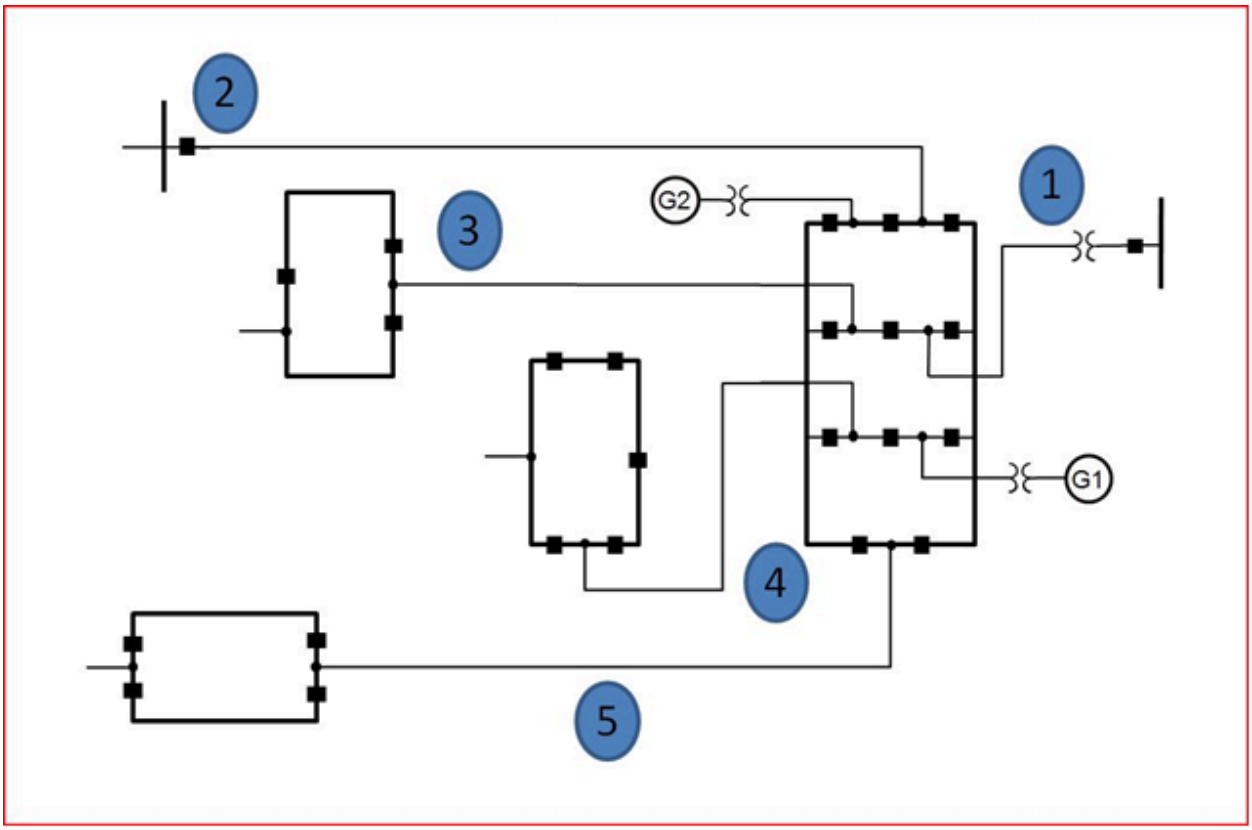


Figure 1 – Example of Five transmission lines for the N-1-1 stability study of a generic location.

It is necessary to analyze total 25 (5 N-1 and 20 N-1-1 contingency scenarios) contingency scenarios for the example plant in Figure 1. It is also noted that 3-phase fault cleared by primary relays is considered for all single contingencies. Fault clearing times are in form of possible ranges for different areas, kV and fault clearance options and the upper values of the respective ranges are used. Existing Remedial Action Schemes are, if available, incorporated in the N-1-1 contingency scenarios.

MITIGATION

Any violation of PJM or other applicable stability criteria as described in this Attachment will be addressed and documented as part of the annual RTEP process.

G.5 Impact Study Procedures Applicable to Wind Turbine Analyses

PJM follows a process of procedures and studies when handling requests to interconnect to the transmission system. These procedures are outlined in PJM Manuals and agreements, particularly PJM's Manuals 14H and 14B and the PJM Open Access Transmission Tariff

(OATT.) In recognition of some of the unique characteristics and challenges posed by wind projects, however, the PJM OATT procedures include certain special provisions applicable to wind farm interconnection requests. Project Developers should familiarize themselves with all applicable PJM procedures and requirements, in consultation with their assigned PJM project manager.

G.5.1 Wind Project LVRT Requirements

In addition to all facets of the standard stability study scope previously discussed, wind generators will be studied during their impact study stability analysis for compliance with the Low Voltage Ride Through Criteria (LVRT.) The LVRT criteria tests the ability to the wind farm generator to maintain operation and interconnection with the system during events that cause extremely low voltage transients as measured at the high side of the transformer that steps up the Wind Farm's voltage to the transmission system (high side of the wind farm GSU.) Peak load conditions are the most stressful for maintaining system voltage so this analysis will be conducted on a peak load power flow model (in contrast to the standard stability analysis that is conducted on an off-peak model.) Based on the results of the standard stability analysis, PJM will determine the most critical three phase faults with normal clearing and phase to ground faults with delayed clearing. The wind generator will be required to maintain its power output to the system following three phase faults cleared in up through 9 cycles (9 cycles includes any applicable margins) and that produce a voltage as low as zero at the high side of the GSU. Actual clearing times plus applicable margins will be used, which may be less than 9 cycles and high side GSU voltages may be somewhat greater than zero. Also the wind farm must maintain output to the system following the most critical phase to ground faults with delayed clearing, using actual clearing times. Applicable clearing time margins will apply to the LVRT test.

G.5.2 Wind Project Reactive Power Modeling

Stability tests will be conducted on a system model with the GSU modeled and zero generator reactive power output (unity power factor.) When power flow analysis does not model the generator step up transformer, the zero generator reactive power output is applied at the collector bus. This base case and the stability analysis will establish power factor or reactive power delivery requirements only if impact study analysis is conducted that demonstrates that the safety or reliability of the system is impacted by the lack of the requirement. System transient, oscillatory, or voltage instability during any phase of the impact study is evidence of system safety or reliability impact. For such results, the least cost remedy that considers system protection, transmission upgrades, or reactive requirements will be determined and specified.

In the event that the transient or voltage instability only affects the wind project (for example when long radial interconnection facilities cause the inability of the wind facility to remain stably interconnected), the wind project will be notified and be requested to provide project design remedies. PJM's analysis of possible remedies will be limited to specifying the size of dynamic reactive device or increased transmission interconnection capacity if such a remedies are sufficient.

G.6 Stability Analyses of Stability Sensitive Local Areas in PJM

The PJM system generally operates to limits determined by thermal and reactive criteria. In some specific instances local areas of PJM or individual plants operate to stability limitations. The PJM transmission system conditions and procedures due to localized thermal, reactive and stability considerations are outlined in PJM Manual 03.

The PJM Transmission Owners are often owners of the facilities that are subject to these procedures and carry out PJM's operating instructions ensuring safe and reliable operation consistent with these guidelines and procedures. PJM, therefore, closely coordinates review of the stability guides and procedures with the Transmission Owners and, when appropriate, Transmission Owners may conduct analysis, subject to PJM's review.

Stability guides applicable to specific plants are reviewed as part of PJM's three year cycle of generator stability analysis that ensures continued compliance with NERC criteria. Local stability guides and procedures are reviewed as necessary when interconnections or transmission changes cause the need for review. Each review is specific to the area or plants operating procedures and guides and confirms or develops modifications to the guide and system upgrades, as appropriate, to maintain reliable operation within applicable criteria.

G.7 Short Circuit

PJM performs short circuit analysis as part of the annual Regional Transmission Expansion Plan (RTEP) baseline assessment. This analysis includes a study of the entire PJM system based on its current configuration and equipment to determine if the short circuit current interrupting duty of circuit breakers is sufficient for the 2 year planning case. In addition, PJM also performs the analysis on the planned system configuration using a 5-year out case. Additional sensitivity studies are performed on years 3 and 4 as needed. The generation and merchant transmission interconnection process (see Manual 14H) also includes short circuit analysis for each requested new interconnection project. The addition of new sources and BES equipment drives most breaker replacements. PJM Planning conducts short circuit analysis to ensure the high-voltage circuit breakers on the transmission system are sufficiently rated to safely interrupt fault currents. These short circuit studies are also referred to as breaker interrupting studies. Since new sources only become committed with relative assurance a few years before scheduled commercial operation and since breaker replacement lead times are only a few years, these analysis are only conducted within the 5-year planning horizon.

The short circuit analysis is performed in accordance with the following industry standards:

- ANSI/IEEE 551-2006 "IEEE Recommended Practice for Calculating Short-Circuit Currents in Industrial and Commercial Power Systems"
- ANSI/IEEE C37.04-1999 "IEEE Standard Rating Structure for AC High-Voltage Circuit Breakers"

- ANSI/IEEE C37.010-1999 “IEEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis”
- ANSI/IEEE C37.5-1979 “IEEE Guide for Calculation of Fault Currents for Applications of AC High-Voltage Circuit Breakers Rated on a Total Current Basis”

The system condition most critical for short circuit analysis on the PJM system is all available generation in-service. This condition is modeled in short circuit reference cases that are specially configured for short circuit analysis. PJM Planning maintains the following short circuit base case representations and associated data:

- 2 year planning representation consisting of the current system plus all facilities planned to be in-service within the next 2 years.
- 5 year planning representation using the 2 year planning representation as the base model and including all system upgrades, generation projects, and merchant transmission projects planned to be in-service from years 2 through 5. This 5 year planning representation is consistent with the PJM RTEP 5 year load flow base case.
- Data file containing current circuit breaker interrupting ratings and other relevant circuit breaker nameplate data for all BES circuit breakers.

The short circuit base cases are maintained using Aspen One Liner and short circuit analysis is performed using the Aspen Breaker Rating Module. The PJM short circuit 2 year planning representation is developed annually with the assistance of the transmission owners and maintained by the PJM Planning.

G.8 Nuclear Plant Specific Impact Study Procedures

Stability analysis of nuclear facilities is conducted during PJM’s three-year cycle of stability review of all existing generating units. Also, interconnections or transmission modifications in the vicinity of existing generating stations, including nuclear stations, may necessitate additional reviews. PJM conducts these reviews consistent with the NERC criteria and certain added criteria specified by the Transmission Owner or plant operator or owner. PJM stability studies take into account coordination with any applicable Remedial Action Schemes. Results of PJM Planning analyses can be found under the “planning” tab material and “committees & groups” tab material on PJM.com particularly:

http://www.pjm.com/planning/planning-criteria.aspx

http://www.pjm.com/planning/rtep-development.aspx

http://www.pjm.com/planning/generation-interconnection.aspx

http://www.pjm.com/committees-and-groups/committees/teac.aspx

PJM will notify PJM System Operations and the affected Transmission Owner in the event that PJM's planning analyses indicate planning study results that violate PJM planning criteria or nuclear specific planning criteria. In addition, results of PJM Impact Studies affecting nuclear facilities are communicated to the affected Nuclear owner and operator.

PJM applies some nuclear plant study procedures that exceed *standard NERC criteria* to be consistent with certain regulatory and safety requirements specific to these facilities. Material contained in the Appendix to this Attachment G provides Nuclear Plant Interface Requirements (NPIR) regarding the nuclear specific testing procedures applied by PJM and Transmission Owner Planning.

G.9 Appendix to Manual 14B Attachment G

This appendix contains Transmission Owner specific criteria applicable to RTEP stability study analyses that may go beyond the NERC system stability performance tests routinely applied by PJM. PJM normal stability testing enforces the NERC criteria that are based on single contingencies and common-mode multiple contingencies. PJM does not permit planned load loss or interruption of firm transmission service for these events, even when such service curtailment may be permitted by the NERC standards. These contingencies are also referred to in this Attachment and Appendix as the "standard" NERC criteria and include the following events:

- System normal,
- Single phase and/or three phase fault (N-1),
- Single phase fault stuck breaker (N-2),
- Three phase fault tower (N-2), and
- Single Phase fault and communication failure (N-2).

More stringent NERC criteria that involve multi-phase faults, non-common mode multiple contingencies, and higher order contingencies (also referred to as "beyond" *standard NERC criteria*) do not routinely form the basis for required PJM RTEP upgrades. Some Transmission Owner criteria, however, as detailed in this Appendix, go beyond the *standard* PJM stability screening criteria and do require remedies. These procedures, as applicable, are applied during PJM RTEP (including interconnection related) stability analyses in addition to PJM thorough testing of *standard NERC criteria* tests and system performance is verified to be stable and within criteria. The Transmission Owner specific criteria are limited to interconnections with the transmission facilities of the respective Transmission Owners.

All PJM testing applies the clearing margins and damping criteria discussed in Attachment G and more stringent criteria when the specific Transmission Owner criteria exceed these standard margins. In all cases PJM applies the criteria in a comparable and not unduly discriminatory fashion to new interconnection projects and existing generators. Violations based on *standard NERC criteria* and standard margins must be remedied by upgrade modifications to

the system. Operating curtailments will generally be an available remedy for issues found for line maintenance outage tests.

G.9.1 Testing of Transmission Owner Criteria

For interconnection studies that pass the *standard* NERC and PJM criteria but produce localized violations based on criteria that are beyond the *standard NERC criteria* and/or margins that exceed standard PJM margins, PJM, in consultation with the affected Transmission Owners, will determine lower cost remedies. For these Transmission Owner tests, planned load loss or interruption of firm transmission service is not allowed when lower cost remedies are available. An available lower cost remedy will be required to address such violations. For example, lower cost remedies that may be considered include:

- Relaying modifications
- Sectionalizing schemes
- breaker upgrades
- Independent pole tripping
- High speed breaker failure schemes
- High speed reclosing
- Fast closing of steam intercept valves
- Braking resistors.

If the search for lower cost upgrades produces none, or in the case of wide-spread system violations such as may be encountered during RTEP baseline stability analysis, then PJM, in consultation with the affected Transmission Owners, will make a more detailed assessment of the violation(s) including factors such as the extent of violations, the events' likelihood, system impact and cost to remedy. Based on the gathered information, PJM will specify a remedy including possible consideration of operating guides, Remedial Action Schemes, and more extensive high voltage upgrade options. See Transmission Owner Planning Criteria at https://pjm.com/planning/planning-criteria/to-planning-criteria for more information.

G.9.2 Nuclear Station Testing

With regard to nuclear station related planning stability analysis, in addition to the *standard NERC criteria* and specific Transmission Owner criteria testing, PJM reviews and enforces criteria testing that can be found under the Planning section of the Nuclear Plant Interface Requirement (NPIR) documents. In some cases the Transmission Owner also performs special nuclear unit stability testing as described in PJM Manual 39 and the NPIR. Together, the analyses that may be performed by the Transmission Owner and PJM's testing incorporate the voltage and stability requirements of the station. PJM ensures Transmission System performance to the specified criteria that enables the station equipment and systems to perform as designed. Nuclear voltage criteria at the Transmission System level, including any voltage drop criteria, are enforced on a system normal and post-contingency basis as described in the NPIR planning requirements. Observed criteria violations during planning assessments affecting

nuclear stations will be evaluated jointly by PJM Planning and PJM Operations consistent with procedures outlined in PJM Manual 39. Appropriate remedies, consistent with this Attachment and the PJM Manuals and Agreements, will be specified to ensure applicable criteria are met. As part of these analyses redispatch of nuclear units is not permitted in an effort to relieve violations. The nuclear owner will be responsible for reinforcements necessary to comply with criteria that are specific to the Nuclear Plant and that are more stringent than the standard PJM and Transmission Owner tests.

The specific nuclear unit planning criteria contained in the NPIR documents are included in the Appendix to this Attachment G when the nuclear plant owner has consented to these excerpts being included here for convenient planning reference. In any instances of a nuclearplant owner preference to maintain confidentiality of this information, it is not reproduced in this manual but is still evaluated and enforced during planning studies.

G.9.3 BG&E Specific Criteria

Additional stability testing applicable to interconnections with BG&E transmission facilities includes tests of three-phase faults at a point 80% of the circuit impedance away from the station under study with delayed (zone two) clearing.

G.9.4 ComEd Specific Criteria

Additional stability testing applicable to interconnections with ComEd transmission facilities includes:

- Three-phase fault on any transmission or generation element with delayed clearing due to a stuck breaker or other protective equipment failure. For situations involving independent pole operated breakers, it is assumed that only one phase of the breaker fails to open and the delayed clearing time is used for the remaining single-phase fault.
- Three-phase fault on any transmission or generation element with delayed clearing due to failure of a Remedial Action Scheme.
- Three-phase fault on all transmission lines on a multiple circuit tower with normal clearing.
- Three-phase fault on any transmission or generation element during the scheduled outage of any other transmission or generation element.

It should be noted that a one-cycle margin is included in all primary-clearing times for faults on the ComEd system, instead of the PJM margins. For more severe, lower probability events such as faults occurring during maintenance outages or faults cleared in delayed time, if lower cost remedies are not available, PJM will retest with the PJM's standard margins as a possible remedy.

The dynamic voltage recovery (DVR) criteria should be satisfied at buses categorized as BES facilities at peak load, given all transmission elements are in 'normal' configuration preceding the event. Following a three-phase fault on the transmission system that results in loss of a

single generator or transmission element, the transmission system DVR must conform to the recovery 'envelope' described below.

- Following the successful clearing of a fault (normal clearing = 6 cycles), the voltage magnitudes should be no less than 70% of their nominal values.
- Within 20 cycles following the clearing of a fault, the voltage magnitudes should be no less than 80% of their nominal values.
- Within 0.5 seconds following the clearing of a fault, the voltage magnitudes should be no less than 90% of their nominal values.
- Within 1.5 seconds following the clearing of a fault, the voltage magnitudes should be no less than the steady-state voltage minimum, typically 92-95% of nominal.

Violation of the DVR criteria can increase the potential for severe voltage problems following a fault and should be mitigated with appropriate reinforcements.

G.9.5 PPL Specific Criteria

Additional stability testing applicable to interconnections with PPL transmission facilities includes:

• **Stuck Breaker and Relay Failure**: Permanent three-phase fault with stuck breaker or other cause of delayed clearing.

• **Double Circuit Tower (DCT) Line Fault**: Permanent three-phase fault involving both circuits of a double circuit line with normal clearing and reclosing sequences, if applicable.

• **Overtripping**: Permanent three-phase fault on one line with an overtrip of another unfaulted line. Both the overtrip and clearing of the faulted line occur in normal primary clearing time. Reclosing sequences, if applicable, should be included.

If assessment of any of the contingency types noted above results in identification of stability concerns in the PPL system, see the table below to determine if a reliability solution is required by PPL ("should be stable"), or if the study results should be reported to PPL for information only ("information only") for awareness and further consideration of the severity of the consequences of the event.

Contingency	TPL-001-4 Contingency Category	Clearing Time	Fault Type		
			230 kV and Above	100 - 229 kV	< 100 kV
Stuck Breaker	E2-A through D	Breaker Failure Clearing Time	3PH (information only)	3PH (information only)	Not Applicable
Relay Failure	E2-A through D	Zone 2 Clearing Time	3PH (should be stable)	3PH (information only)	Not Applicable
DCT Line Fault	E2-F	Normal Clearing Time	3PH (information only)	3PH (information only)	Not Applicable
Overtripping	E2-F	Normal Clearing Time	SLG (information only)	SLG (information only)	Not Applicable

G.9.6 Implementation of the NPIR for Planning Analysis

PJM incorporates the Nuclear Plant Interface Requirements (NPIRs) into its planning processes in accordance with the applicable NERC standards. PJM performs these planning analyses consistent with the NPIR planning requirements and its Regional Transmission Expansion Planning requirements.

G.10 NERC Standard PRC-023 – Transmission Relay Loadability

Background

The purpose of the standard is to ensure that protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults. There are a number of requirements that specify how protective relays should be set so that they will not limit loadability of a circuit. One of the requirements of the Standard (R6) is for the Planning Coordinator to determine the facilities that must comply with requirements R1 through R5 of NERC standard PRC-023.

In accordance with Attachment B of PRC-023, the following circuits are subject to Requirement R6:

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.
- Transmission lines operated below 100kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

Process to determine PRC-023 Critical Facilities

PJM staff will conduct an assessment at least once each calendar year, with no more than 15 months between assessments applying the criteria in accordance with Attachment B or PRC-023 to determine the circuits for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. PJM will maintain a list of circuits subject to PRC-023 per application of Attachment B and provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 days of any changes to that list. The test will monitor all required facilities in accordance with Attachment B of PRC-023 as described below.

NERC Standard PRC-023 Transmission Relay Loadability - Attachment B

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

- The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.
- The circuit is a monitored Facility of an IROL, where the IROL was determined in the planning horizon pursuant to FAC-010.
- The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.
- The circuit is identified through the following sequence of power flow analyses performed by the Planning Coordinator for the one-to-five-year planning horizon
    - Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).
    - For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.
    - When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.
    - The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.
- If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.
- If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.
- If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.
    - The Radially operated circuits serving only load are excluded.
- The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in the NERC Standard PRC-023 Transmission Relay Loadability - Attachment B Criteria above, in consultation with the Facility Owner

- The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

G.11 PJM Capacity Import Limit Calculation Procedure

Introduction

- The purpose of PJM Capacity Import Limit Calculation Procedure is to establish the amount of power that can be reliably transferred to PJM from defined regions external to PJM.
- The PJM Capacity Import Limit is calculated annually and is used to confirm that import capability into the PJM system is greater than the sum of the PJM Capacity Benefit Margin (CBM) and confirmed Long Term Firm Transmission Service. The imports into PJM will therefore be comprised of firm transmission service reservations and non-firm energy purchases from the external supply regions described in section 3 below.

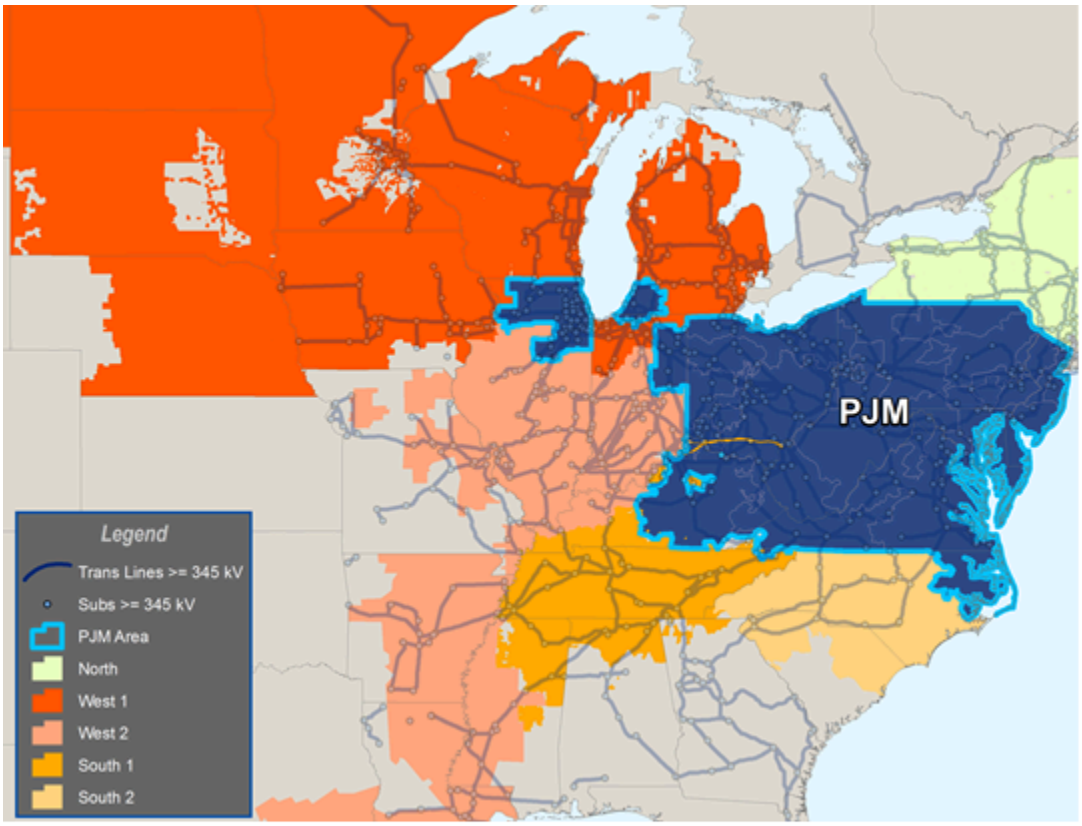
General Procedures and Assumptions

The system power flow model will be based on the latest summer peak RTEP base case.

- The base case will contain confirmed Long Term Firm Transmission Service for the study period as identified in the PJM OASIS.-.
- The PJM dispatch will reflect a PJM generation deficiency situation independent of the defined regions external to PJM. Thus, non-PJM regions are operating normally and are assumed to be able to supply PJM with power up to the lower of the Capacity Import Limit or the limit of their available reserves. Load in PJM and all external regions will be modeled at a 50/50 load level and load. The amount of reserves considered available from any adjacent non-PJM area may be adjusted to reflect historical data and expected future conditions.
- For thermal analyses, all Eastern Interconnection BES facilities (100 kV and above) will be monitored. All PJM internal BES single contingency events and selected non-PJM BES contingency events will be considered.
- For voltage analyses, all PJM BES facility voltage magnitude and drop limits will be monitored and selected non-PJM BES facility voltage limits will be observed. In addition, any part of the Eastern Interconnection that would experience voltage collapse will be evaluated. The voltage analyses are subject to all PJM internal BES single contingency events and selected non-PJM BES contingency events.
- The following operating procedures will be employed as necessary.
    - Adjustments of Phase Angle Regulators (PARS which PJM or PJM member companies control (within existing agreements for emergency operation). For the PJM/NYISO PARs in particular, flows will be set according to the ratios provided in Attachment B Section (B.3) (VII) (P), but be based on both the firm and any non-firm emergency assistance from NYISO.

    - The activation of any approved PJM or PJM member company operating procedure (procedure descriptions are available in Manual 3.)

- The activation of any approved PJM or PJM member company operating procedure (procedure descriptions are available in Manual 3.)
    - Redispatch and implementation of load management schemes will not be considered as part of this study.
- Methodology
    - The external supply will come from those regions within the Eastern Interconnection that are considered as part of the PJM Reserve Requirement Study. These external supply regions will be divided into five zones for the purpose of determining both a simultaneous import limit and five directional non-simultaneous import limits. During the simulation of the simultaneous limit, the amount of power from each source zone will be optimized. The five zones are:
        - Northern Zone: NYISO & ISO NE
        - Western Tier 1 Zone: MISO East and MISO West
        - Western Tier 2 Zone: MISO Central & MISO South
        - Southern Tier 1 Zone: TVA & LGEE
        - Southern Tier 2 Zone: VACAR (non-PJM)
- These zones may be periodically modified based on changing system patterns or historical operational data.



- PJM will scale the load uniformly down at a constant power factor in the external supply zone(s) and scale PJM generation (MW) down uniformly to simulate the power imported from external resources.
- In order to exclude transmission facilities from the monitored list which are not significantly affected by the increase in import power from the external resources, PJM will employ an outage transfer distribution factor cutoff of 3% based on the external zone(s) supplying the resources.
- The aggregate power transfer into PJM, at the point where any increase in this MW transfer would result in a reliability criteria violation, less the applicable PJM Capacity Benefit Margin (CBM) will be defined as the simultaneous PJM Capacity Import Limit.
- Similar approach will be employed to determine the maximum power transfer from any one of the five defined zones into PJM. For determining the non-simultaneous limits, a portion of the CBM will be allocated to each of the five directional transfer paths in proportion to the ratio of their transfer amount divided by the simultaneous Capacity Import Limit plus the PJM CBM.

G.12 NERC Standard FAC-002 – Facility Interconnection Studies

Background

As the Transmission Planner and Planning Coordinator, PJM is responsible for the development of the Regional Transmission Expansion Plan (RTEP) for the PJM system. The planning process which ultimately culminates in the PJM RTEP base case is driven by three planning paths. The three paths include planning activities associated with:

- Baseline Projects
- Supplemental Projects
- Customer-Funded Upgrades

Each of the planning activities examine the reliability impact of: (i) interconnecting new generation, transmission, or electricity end-user Facilities and (ii) existing interconnections of generation, transmission, or electricity end-user Facilities seeking to make a qualified change as defined by PJM under Requirement R6 of FAC-002.

Qualified Change

For the purposes of FAC-002 R6, PJM defines a qualified change for a facility interconnection as follows:

Table G.12.1 Qualified Change for End-User Facilities

Description	Examples
Facility change leading to change in: 1. End-User Facility topology or 2. Protection system changes impacting contingency definition or 3. The electrical characteristics of the facility or 4. Facility ratings that either of which may impact BES performance	• Increase or decrease in load • Changes to the number of feeds in an existing End-User Facility

Table G.12.2 Qualified Change for Transmission

Description	Examples
Facility change leading to change in: 1. Transmission system topology or	• Increase or decrease in rating

Table G.12.2 Qualified Change for Transmission	
2. Protection system changes impacting contingency definition or 3. The electrical characteristics of the facility or 4. Facility ratings that either of which may impact BES performance	• Change in facility impedance • Reconfiguration

Table G.12.3 Qualified Change for Generation	
Description	**Examples**
Go reports anticipated changes of the electrical characteristics following execution of the applicable interconnection agreement. PJM evaluation of changes requires more detailed analytical studies	• Change in generator electrical characteristics • Chang ein turbine type

Examples provided are for illustrative purposes only and are not meant to be exhaustive.

Attachment H: Power System Modeling Data

H.1 Power System Modeling Data

Accurate power system modeling data is a key component of quality power system analysis. PJM System Planning uses a variety of models and analytical techniques to create and maintain the simulation models used for the RTEP studies. The intended use of this Attachment is to supplement existing documentation by PJM and other entities that specify accurate modeling data requirements. PJM will continue to follow the data guidelines and standards set forth by NERC as part of the MOD standards and the Eastern Interconnection Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG) Procedural Manual.

Attachment J contains the checklist for the new equipment energization process to be utilized by Transmission Owners and Designated Entities from inception to energization of upgrade projects.

H.1.1 Load Flow Analysis Models

Base case creation is a collaborative process between PJM and its members. From a technical standpoint PJM follows the guidelines set forth in the ERAG MMWG Procedural Manual. In the following sections, the logistics and transfer of information between PJM and its members are detailed.

Annual Updates

In the late third quarter of each year, PJM will ask Transmission Owners to review and update base case and project files in Model on Demand. The base case updates will include committing case corrections along with in service projects with as built data to the base case. Project files will be updated for status, scope change, and in service date change. PJM will then use Model On Demand to build trial 1 cases for +5 year Summer, Light Load, and Winter, which will be sent to Transmission Owners for review. Transmission Owners will provide:

- Network updates to the model that will advance the case to represent a current year + 5 base case with respect to the 1st Quarter of the following year. This update should be reviewed for correctness and compatibility with the final version of the base case under development
- Complete NERC P1, P2, P3, P4, P5, P6 and P7 contingency file updates that correspond to the updated network model (Include any contingencies which may not change the powerflow model, but change contingency definitions)
- Maximum credible disturbance (NERC TPL-001-5.1 Table 1 Extreme Events) contingencies
- Any other significant changes such as new load or block load additions

- Support, if necessary, for the development of network models for additional years and demand levels for both near term (years 1 through 5) and longer term (beyond 5 years) analyses.
- Verification that all baseline, network and supplemental upgrades are included in the updated case along with a written description of any case modifications.
- Notification of any changes to tie lines whether they are ties internal to PJM or to external companies.

Interim Updates and Communication of Significant Modeling Updates

In the event that PJM makes a major update to the RTEP analysis models outside of the annual model update window, PJM will notify PJM Transmission Owners of the modeling update through the Transmission Expansion Advisory Committee (TEAC) meetings. Also,

PJM will notify neighboring entities that PJM determines may be impacted. In addition to the notification, PJM will make the updated affected models available upon request.

Generation Owner Requirements:

- Specific information regarding generator capability per MOD-032

H.1.2 Load Flow Modeling Requirements

In addition to the guidelines set forth by NERC and the ERAG MMWG procedural manual, PJM uses several specific procedures in establishing the base case so that it represents the best starting point for the annual RTEP analysis.

Generator step-up transformers

Generator models should represent the physical plant lay-out to the extent possible, explicitly modeling generator step-up transformers (GSUs) and Station Service loads (aka Auxiliary loads). This applies to units above 20 MW and connected to the BES system, consistent with BES requirements. Plants consisting of multiple units aggregating to 75 MW or more also require explicit representation of GSUs and station service loads.

Modeling of Outages

Known outages of Generation or Transmission Facilities are selected based on a documented technical rationale and will be included under those system peak or off-peak conditions in the appropriate base case model. PJM may not model these outages in every case that is used for RTEP analysis, but will select appropriate scenarios to asses these changes. PJM will perform analysis on the P0 and P1 planning event categories for steady state analysis and the P1 planning event category for stability analysis as defined in Table 1 of TPL-001-5.1. Additionally PJM will analyze a subset of maintenance outages submitted through eDart under those system peak or off-peak conditions.

Interchange

The PJM net interchange in the summer peak case is determined by the firm interchanges that are represented in the PJM OASIS system. That interchange, in the summer peak case, shall be represented as 100% of the confirmed full path (must be confirmed in both PJM and external zone OASIS) firm import and export reservations. Reservations associated with individual generation units, or group of units at a facility, shall be used in representing the interchange. The interchange in light load cases follows the light load criteria as defined in the Light Load Reliability Analysis in section 2.3.10 of this manual.

Generator Reactive Capability

Annually, PJM updates the model for the generator reactive capability (GCAP) of each generator based on data used by PJM Operations, which includes default limits obtained from the most up to date d-curves as well as data provided by the Generator Owners.

Interconnection Projects With Final Agreements

PJM includes projects with a signed final agreements into the base case as well as verifying the accuracy of projects that have not yet signed a final agreement. PJM also includes the interconnection, ratings and associated upgrades for each of these projects. Transmission Owners will verify the accuracy of the points of interconnection and the associated upgrades in their zones.

Real and Reactive Load

Each TO is responsible for modeling the active (real) and reactive load profile in its zone. PJM will scale the load in each zone to the targeted values reported in the latest annual PJM load forecast report.

Real loads will be scaled uniformly in each zone to meet the PJM 50/50 load forecast less any Demand Response (DR), or Behind the Meter (BTM) generation as necessary. Real loads will also be scaled uniformly within each zone for off-peak analysis. Reactive load in each area will be scaled at a constant power factor along with the real load for peak load analysis. For off-peak analysis including light-load, PJM will provide a case to the Transmission Owners, at their discretion, for updating their zonal reactive load profile.

Any deviation from the above method of load modeling method, associated with specific test procedures such as the PJM Load Deliverability Procedure or the PJM Light Load Reliability Test Procedure will be defined specifically in other sections of this manual.

PJM will coordinate with TOs on an individual basis to ensure that non-conforming loads are properly modeled and not uniformly scaled.

Voltage Schedules

The setting of voltage schedules is crucial to the robustness of cases. PJM allows Transmission Owners to supply generator voltage schedule data. If the data is not provided PJM will use the default voltage schedules as defined in PJM Manual 03.

H.1.3 Submittal of Load Flow Data

Attachment J contains the checklist for the new equipment energization process to be utilized by Transmission Owners and Designated Entities from inception to energization of upgrade projects.

Acceptable Data Formats

PJM sanctioned software:

- PSS/E – power flow modeling software
- TARA – steady state power flow analysis tool

For PSS/E users, cases should be submitted to PJM in a ".SAV" format in a PSS/E version that is readable by the current version of PSS/E that MMWG is using.

For users of PSLF or other modeling software, cases shall be submitted to PJM in a ".RAW" format that is PSS/E compatible and is readable by the current version of PSS/E that MMWG is using.

PJM's migration of PSS/E versions may slightly lag MMWG, in that case it is acceptable to provide updates formatted for the current version that PJM is using.

TO's can submit data in an agreed to version if they are unable to export to the latest MMWG compatible version.

Timing

Transmission Owners must comply with the schedule dictating the timeliness of the case creation process which will be included in the initial email sent to kick off the process. This schedule will include a minimum of 4 weeks to provide updates to the case and corresponding files for the first iteration, and 2 weeks for the second iteration.

Load Flow Data Quality

In the event that data provided by Transmission Owners does not pass all of the testing included in the MMWG data checker, PJM may request updated data.

Transmission Owners must provide unique bus names or circuit ID's for each winding of all transformers.

Bus numbers must be within the allocated bus number range for each company.

Conventions used for the naming of Machine ID's vary for different TO zones. PJM will coordinate with each TO individually to align with their preferred convention.

Certain specific modeling and naming conventions which must be followed by all TO's include:

- High/Low Pressure units should be modeled on the same bus and designated with the corresponding machine ID "H" and "L".
- No other machine ID should be named "H" or "L".

With the exception of High/Low Pressure units, multiple machines modeled on the same bus must have the same status. Offline machines should not be modeled on the same bus as machines which have a status of online.

Machines at the same plant with different statuses should be modeled on separate busses connected by a very low impedance line (X=.002) as defined in the MMWG manual.

H.1.4 Short Circuit Analysis Models

Short Circuit data procedures are documented in the Attachment G.7 of this manual, which references ANSI/IEEE 551. The intended use of this attachment is to supplement these procedures and outline the data requirements which PJM follows in creating the short circuit cases used for analysis.

Short circuit models should be provided in Aspen ".olr" format, if possible.

Each TO provided Aspen ".OLR" case should model only the TO area and its tie lines. No outside areas should be included in the submission.

All area numbers in the TO provided cases should be consistent with MMWG designated area numbering convention. Area numbers such as 1, 2, 3, etc. are not acceptable.

Generation owners must submit to PJM all their breaker data for breakers rated above 100 kV.

Transmission Owners must submit an excel sheet containing explanations for outaged and out-of-service equipment that is normally in-service.

Timing

In the 1st quarter of each year, PJM will send the Transmission Owners an initial current year +5 impedance network model. This case is based on the most up to date PJM short circuit case combined with the previous year's RTEP case containing all upgrades, MTX projects, and generation projects that have completed Decision Point II requirements identified during that RTEP cycle.

In the 4th quarter of each year, PJM will send the Transmission Owners an initial current year +2 impedance network model. This case is based on the most up to date PJM short circuit case combined with the previous year's RTEP case containing all upgrades, MTX projects, and

generation projects that have completed Decision Point II requirements identified during that RTEP cycle.

Transmission Owners must comply with the time schedule of the case creation process which will be included in the initial email sent to kick off the process. This schedule will include a minimum of 4 weeks to provide updates to the case and corresponding files. Once all cases and corresponding files have been submitted to PJM, a +2 case is created and analysis performed to determine overdutied breakers. TOs are then given another 4 weeks to confirm any new overdutied breakers. After the +2 year short circuit case is finalized, the +2 year case is then used to create the+5 year short circuit case for performing the short circuit studies and identifying the new system issues. The identified issues will be sent out to the Transmission Owners who will have 4 weeks to provide solutions to address these issues.

H.1.5 Stability Analysis Models

The case used for stability and dynamic studies is developed by PJM based on information from the Regional Transmission Expansion Plan (RTEP) case prepared by PJM Interconnection and the MMWG case prepared by Powertech Labs for the Eastern Interconnection Reliability Assessment Group (ERAG).

When preparing the base case for stability and dynamics, the ERAG case provides the information for the areas outside PJM while the RTEP case provides the PJM information (e.g. load forecast, network configuration). When combining the ERAG and the RTEP cases, care should be taken to preserve the ties between the PJM areas and the rest of the Eastern Interconnection.

All generator projects active in the PJM interconnection process that have been studied must be included in the base case for stability and dynamics. In some instances, the RTEP model for such projects may not be detailed enough for use in stability studies. In this situation, the case must be updated to make sure that all detailed components associated with this project are included in the stability and dynamics power flow model (e.g. generator step-up transformer, loads).

In addition to updating the power flow case with the latest network information, the dynamic models must also be updated to reflect the changes introduced by the RTEP case and the stability and dynamic studies performed by PJM. In this regard, the dynamic data file from the ERAG MMWG case is updated so that the dynamic models for the generators in the PJM areas are matched against the new power flow information from the RTEP. The dynamic model for each generator in the Cycle must also be added to the dynamic data file.

The resulting power flow case, the dynamic data file and supporting files required for a complete stability and dynamics base case need also to be correlated and reviewed to determine inconsistencies as well as missing or questionable data. A base case is considered to be finished when, after the review, it compiles, links the models to the PSS/E main structure and initializes correctly. An acceptable condition for a finished base case is when simulated system

dynamics, using this case, do not deviate from the initial conditions for any simulation setup with no disturbances applied to the system.

Timing

In the first half of each year, PJM will build stability cases based on updated previous year RTEP power flow model and the latest ERAG dynamic cases. In this period, PJM may request the Transmission Owners for load models for dynamic studies, and for other supporting data if necessary. Transmission Owners must comply with the time schedule of the stability case creation process which will be included in the request email.

Stability and dynamics base cases:

- Stability is assessed using a summer peak load and a light load condition. The summer peak stability case has the load profile of the RTEP summer peak case and corresponds to the demand expected to be served in the specific planning year. The light load stability case represents 50% of the summer peak load and is developed by scaling down the summer peak load case at the same power factor.
- For simplicity, it is recommended to first build the summer peak case and then update that case to reflect the second load condition (light load). This approach provides two cases that are common in bus numbers and network information. Updates to both cases, such as addition or removal of proposed lines or interconnection projects would be easy to handle due to the uniformity.

After the power flow case has been finalized and revised, the dynamic data file from the dynamic data file will be updated to reflect the changes that were introduced by the addition of the PJM areas from the RTEP case and generation interconnection studies. It is important to note that the RTEP case and the ERAG case complement each other. RTEP case information is used for future generation projects and transmission upgrades which don’t exist in the ERAG case and ERAG case consists of information of existing units.

The light load case (50% peak) is derived from the summer peak case. This approach ensures consistent bus numbers and network information in both cases, making addition or removal of proposed lines or interconnection projects easy to handle. After the summer peak case is completed, the PJM load is scaled down to a load representing 50% of the 50/50 load. The areas outside PJM are updated with the light load case from the corresponding ERAG MMWG case. Note that generation and shunt capacitors may be turned off or disabled in order to achieve convergence of the power flow. In addition, all pumped storage hydro units are modeled in the pumping mode with their governors and power systems stabilizers deactivated or adjusted to reflect the appropriate operating condition.

Generation/Transmission Owner Responsibilities:

- Provide necessary supporting data for stability case build upon PJM’s request including but not limited to: topology information and dynamic modeling and station loads

- Provide station loads, including power factors and load representation data (CONL file) if the load representation is different from the one in the ERAG MMWG series
- Verify upgrades and generator modeling (MVA base & Topology)

If there is any discrepancy between the RTEP case and the ERAG MMWG case for existing units, PJM will follow up with the Generation owner with assistance from the TO to insure that the most current data is used.

A complete base case (summer peak or light load) must include at least:

- A power flow file: This file contains the network information and provides the initial conditions for the dynamic models.
- A dynamic data file: This file contains all the information necessary to simulate the dynamic response of the various system components.
- A gnet file: This file contains the information of those generators that do not have a dynamic model. Any generator listed in this file is considered as a negative MVA load.
- A conl file: This file indicates how loads will be modeled based on a combination of constant MVA, constant current and constant admittance. It is strongly recommended that each TO develop more accurate load representation for stability and dynamics studies

Dynamics Data Submittal Requirements and Guidelines:

The Multiregional Modeling Working Group (MMWG) provides the following topics pertaining to dynamics data submittal requirements and guidelines. This information is accessible in Appendix II of the MMWG Procedure Manual V5. A hyperlink to the manual is located at the bottom of this section.

- Power Flow Modeling Requirements
- Bus name identifiers for synchronous condensers, Static VAr Compensators (SVCs) modeled as generators, switched shunts, relays, and HVDC terminals.
- Step-up transformer representation requirements for both MMWG power flow cases and non-MMWG power flow cases.
- Resistance and reactance data placements for step-up transformers represented in the power flow generator data records.
- Xsource value representations in the power flow generator data record.
- SVC representation requirements in power flows.
- Dynamic Modeling Requirements
- Synchronous generator and condenser modeling / associated data requirements and exceptions.
- Additional representation requirements and exceptions for synchronous generators and condensers modeled as described in Requirement II.1.

- PSS/E modeling requirements for any other types of generating units and dynamic devices.
- Exceptions to the use of standard PSS/E dynamic models.
- Required written documentation and its submittal procedures for user-defined modeling in MMWG cases.
- Generating unit, synchronous condenser, and other dynamic device requirements for netting.
- Lumping conditions of similar or identical generating units at a plant.
- Location requirements for per unit data.
- Exception procedure for any requirements listed.
- Dynamics Data Validation Requirements
- Dynamics data screening requirements
- Preliminary procedures to undergo before regional data submittal to the MMWG coordinator.
- Material required by each region to validate the dynamics model.
- Guidelines
- Additional documentation that should be submitted with dynamics data.
- Information pertaining to parameters for representing loads via the PTI PSS/E CONL activity that the regions should provide to the MMWG.

Location of MMWG Procedural Manual:

https://rfirst.org/ProgramAreas/ESP/ERAG/MMWG/ERAG%20%20MMWG%20Library/MMWG_Procedural_Manual_V29.pdf

Attachment I: Steady State & Stability Performance Planning Events

I.1 NERC TPL-001-5.1 Table 1

Manual or automatic load shed is not permitted for any P0 - P7 condition.

NERC TPL-001 Events				PJM		
NERC Category	**Initial Condition**	**Event[1]**	**Fault Type[2]**	**Thermal Limits**	**Low Voltage Limit ****	**High Voltage Limit ****
P0 No Contingency	Normal System	None	N/A	Apply normal limits, the actual % may differ, depending on the TO zone	PJM Planning will use the same voltage limits that are used in PJM Operations for both voltage magnitude and voltage deviation. Emergency limits are used for normal, single contingencies and multiple contingencies. For Transmission Owner Criteria, PJM will default to the operations limits unless the TO limits are more conservative.	
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	Apply emergency limits, the actual % may differ, depending on the TO zone		
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault[7]	N/A			
		2. Bus Section Fault	SLG			
		3. Internal Breaker Fault[8] (non-Bus-tie Breaker)	SLG			

		4. Internal Breaker Fault (Bus- tie Breaker) [8]	SLG		

NERC TPL-001 Events				PJM		
NERC Category	**Initial Condition**	**Event[1]**	**Fault Type[2]**	**Thermal Limits**	**Low Voltage Limit ****	**High Voltage Limit ****
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	Normal limits after the 1st contingency, emergency limits after the 2nd contingency		
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker)*[10]	Normal System	Loss of multiple elements caused by a stuck breaker10 (non-Bus-tie Breaker) Attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6] 5. Bus Section	SLG	Apply emergency limits, the actual % may differ, depending on the TO zone		
		6. Loss of multiple elements caused				

		by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus			

P5 Multiple Contingency *(Fault plus non-redundant component of a Protection System failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6] 5. Bus Section	SLG		

NERC TPL-001 Events				PJM		
NERC Category	**Initial Condition**	**Event[1]**	**Fault Type[2]**	**Thermal Limits**	**Low Voltage Limit ****	**High Voltage Limit ****
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit	Loss of one of the following: 1. Transmission Circuit 2. Transformer[5]	3Ø	Normal limits after the 1st contingency, emergency limits after		

	2. Transformer[5] 3. Shunt Device[6] 4. Single pole of a DC line	3. Shunt Device[6]		the 2nd contingency	
		4. Single pole of a DC line	SLG		
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of any two adjacent (vertically or horizontally) circuits on common structure[11]	SLG	Apply emergency limits, the actual % may differ, depending on the TO zone	

Note:
(*please note that footnotes 3, 4 and 12 have been intentionally skipped to preserve alignment with subsequent footnote numbering.)

1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.

2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.

5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.

6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.

7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.

8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.

9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled ‘Initial Condition’) and a corrective action when achieved through the

appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.

10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.

11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.

13. For purposes of this standard, non-redundant components of a Protection System to consider are as follows:

a. A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times

b. A single communications system associated with protective functions, necessary for correct operating of a communication-aided protection scheme required for Normal Clearing (and exception is a single communications system that is both monitored and reported at a Control Center);

c. A single station dc supply associated with protective function required for Normal Clearing (an exception is a single station dc supply that is both monitored and reported at a Control Center for both low voltage and open circuit);

d. A single control circuitry (including auxiliary relays and lockout relays) associate with protective functions, from the dc supply through and including the trip coil(s) of the circuit

breakers or other interruption devices, required for Normal Clearing (the trip coil may be excluded if it is both monitored and reported at a Control Center).

Attachment J: Checklist for New Equipment Energization Process

The following checklist has been created for use by Transmission Owners and Designated Entities as a guideline for what is required by PJM throughout the baseline/supplemental transmission upgrade process from inception to energization.

For more detailed information please refer to the training series: Transmission Planning, Modeling, and Energization which can be accessed from any of the following pages on pjm.com:

http://www.pjm.com/planning/rtep-development.aspx;

http://www.pjm.com/planning/rtep-development/powerflow-cases.aspx

http://www.pjm.com/planning/design-engineering.aspx;

http://www.pjm.com/markets-and-operations/ops-analysis.aspx

Project Phase [1]	Task	Delivery	Timeframe	PJM Manual Reference	PJM Contact Depart
P	Submit minimum required rating (lines and xfmrs)	Email to contact	Before Project Approval	M-14B	Transmission Planning
P	Submit planning model parameters	IDEV/Project File	Before Project Approval	M-14B	System Planning Modeli Support
P	Submit planning contingency changes	CON File	Before Project Approval	M-14B	Transmission Planning
P	Submit breaker diagrams	Email to contact	Before Project Approval	M-14B	Transmission Planning
P	Project Description/	Email to contact	Before Project Approval	M-14B	Transmission Planning

Project Phase [1]	Task	Delivery	Timeframe	PJM Manual Reference	PJM Contact Depart
	Cost/Time Estimate				
EP	Construction Schedule/ Project Sequence	Email to contact	6-8 months prior to UC phase	M-14C	Infrastructure Coordinati
EP	Submit projected outage timeframes	Email to contact	6-8 months prior to UC phase	M-14C	Infrastructure Coordinati
UC	Quarterly updates	Email to contact	Throughout UC phase	M-14C	Infrastructure Coordinati
EP/UC	Submit as built impedance and all other applicable equipment parameters (i.e. Tap Settings, Capacitor Size etc.)	eDART – Network Model Ticket	6-12 months prior to IS	M-03A; 3.2	Model Management
EP/UC	Submit final In-Service Date	eDART – Network Model Ticket	6-12 months prior to IS	M-03A; 3.2	Model Management
EP/UC	Submit target build date	eDART – Network Model Ticket	6-12 months prior to IS	M-03A; 3.2	Model Management
EP/UC	Submit equipment names	eDART – Network Model Ticket	6-12 months prior to IS	M-03A; 3.2	Model Management

Project Phase [1]	Task	Delivery	Timeframe	PJM Manual Reference	PJM Contact Depart
EP/UC	Submit final one-line diagrams	eDART – Network Model Ticket	6-12 months prior to IS	M-03A; 3.2	Model Management
EP/UC	Submit Transmission Outage Tickets	eDART	2-12 months prior to IS	M-03; 4.2	Transmission Operations
EP/UC	Submit Ratings (Lines and Transformers)	eDART – TERM	No later than 2 weeks prior to IS	M-03A; 3.2	Real-Time Data Manage TERMTickets@pjm.com
EP/UC	Submit Telemetry	Email	No later than 2 weeks prior to IS	M-03A; 3.2	Real-Time Data Manage PJMTelemetrySupport@
EP/UC	Submit As built data	Project File	IS Date	M14B	System Planning Modeli Support
UC/IS	Notification of In-Service status	Email	Once facility is energized	M-14C	Infrastructure Coordinati

1Key: **P** = Pending (or before Pending), **EP** = Engineering and Procurement, **UC** = Under Construction, **IS** = In-Service

Note:
For maximum exposure to various members, identical copies of this table can be found in PJM Manuals 03A, 14B, and 14C

Attachment K: CIR for ELCC Transition

- A “transitional resource” refers to any resource that by April 10, 2023 either has an ISA (“existing unit”) or is active in the PJM interconnection queue (“existing queue unit”) and submits a CIR uprate request into the New Services Queue along with a request to be considered as a transitional resource. PJM will post the transitional resource request form to the PJM website along with the 1/25/2023 Markets & Reliability Committee meeting materials that will contain the instructions for filling out and submitting the form and the information required. Only CIR uprate requests that do not involve a physical modification to the resource will be eligible for transitional resource designation. The submittal of the CIR uprate request into the New Services Queue and any subsequent withdrawal of the request from the New Services Queue will be done and treated in a manner that is consistent with the PJM Manuals and PJM Governing Agreements. The resource will no longer be considered a transitional resource if it withdraws its CIR uprate request.

- The **“**transitional resource MW ceiling” refers to, for Variable Resources, up to the lower of the summer regional percentile output for the resource type or the requested CIRs. For all other resource types, up to the lower of their MFO or requested CIRs. PJM will post the summer regional percentile outputs for Variable Resources in the TEAC RTEP assumptions slides that will typically be released in January each year during the transition period in a slide entitled “Wind & Solar Harmer Dispatch As Percent of Maximum Facility Output”. PJM will also post the summer regional percentile outputs for Variable Resources for the 2025/2026 BRA to the PJM website along with the 1/25/2023 Markets & Reliability Committee meeting materials.

- The “transition period” refers to the period of time required to process a CIR uprate request for a transitional resource in the PJM interconnection queue such that the amount of CIRs requested under the CIR uprate request in the New Services Queue is eligible to participate in RPM. During the transition period, a transitional resource may receive transitional system capability up to the transitional resources’ MW ceiling. After the transition period or upon withdrawal of the CIR uprate request from the PJM interconnection queue, the designation of transitional resource is removed.

- The “transitional system capability” refers to identified locational transmission system injection capability that is available in the full summer generator deliverability test (single contingency and common mode outage) for the applicable BRA Delivery Year during the transition period beyond that required to support all PJM CIRs considered in the interim CIR study. The transitional capability is calculated for transitional resources that are eligible to participate in the BRA Delivery Year under study and is capped at the transitional resource MW ceiling. The transitional capability may vary for each BRA during the transition period and is subject to other known locational reliability restrictions such as stability and voltage. The allocation of the transitional system capability prior to each BRA

during the transition period will be based on a cluster approach using the distribution factors and the transitional resource MW ceilings along with identified reliability constraints.

- The **"**transitional system capability study" refers to a study performed prior to each BRA during the transition period for CIR uprate requests for all transitional resources that are eligible to participate in the BRA Delivery Year under consideration. Transitional resources that submit a request for higher CIRs to PJM along with a request to be considered as a transitional resource by April 10, 2023 will have their CIR uprates processed in the New Services Queue and will be part of a transitional system capability study prior to each BRA (estimated 2025/26 through 2029/30 BRAs) during the transition period to determine whether the transmission system is capable of delivering outputs above the existing queue unit's eligible CIRs. Such eligible transitional resources will have their hourly output capped in the ELCC study and accreditation process at the resource's transitional system capability, which will consider summer generator deliverability testing (single and common mode outages) and other reliability tests as needed to ensure the resources are deliverable for the Delivery Year under consideration. The transitional system capability assigned to the resource will be the greater of the existing queue unit's eligible CIRs for the applicable BRA Delivery Year or the transitional resource MW ceiling.

A transitional system capability study will be performed prior to each BRA during the transition period for CIR uprate requests for all resource types. Transitional resources that submit a request for additional CIRs to PJM along with a request to be considered as a transitional resource by April 10, 2023 will have their CIR uprates processed in the New Services Queue of the PJM interconnection queue and will be part of a transitional system capability study prior to each BRA (estimated 2025/26 through 2029/30 BRAs) during the transition period. The transitional system capability study will determine whether the transmission system is capable of delivering outputs above existing queue unit's eligible CIRs. Such qualifying transitional resources will have their hourly output capped in the summer portion of the ELCC study and accreditation process at the resource's transitional system capability, which will consider summer generator deliverability testing (single and common mode outages) and other reliability tests for the Delivery Year. The transitional system capability assigned to the resource will be the greater of the existing queue unit's eligible CIRs for the applicable BRA Delivery Year or the transitional resource MW ceiling.

The allocation of identified additional system capability among the transitional resources will be performed using the following steps.

1. Gather inputs for allocation of transitional system capability:
    a. Overloaded flowgates and overloaded amounts with and without the CIR uprate requests
    b. DFAX and MW value requested to be considered in the study

2. Pre-processing:
    a. Eliminate overloaded flowgates where the CIR uprate request does not contribute
    b. Eliminate any CIR uprate request that contributes to a flowgate that is already overloaded without any CIR uprate requests; such transitional resources will not receive any transitional system capability.
3. Determine allocation of additional system capability among the transitional resources:
    a. For remaining flowgates (not overloaded but for the CIR uprate requests) use DFAX and MW [value of the CIR uprate requests plus available headroom to determine amount of CIR uprate request MWs the system can accommodate from each transitional resource.
    b. For transitional resources connected at the same electrical location, allocation of additional system capability shall be done on a pro-rata basis according to the amount of CIR uprate MWs requested for each transitional resource.
4. Once allocation of additional system capability among the transitional resources is complete, then rerun generator deliverability to ensure no remaining thermal or voltage violations exist.

Revision History

Revision 55 (12/20/2023):

- Periodic Review
- Added qualifying language to the manual where losing more than 300 MW of load will impact numerous customers. Sections that were revised include:
  - 2.3.8 NERC P3 and P6 "N-1-1" Analysis
  - Attachment D: PJM Reliability Planning Criteria
  - Attachment D-1: Load Loss Definitions
- Revised Section 2.9 CSPA Analysis bullet 1 to include the concept of impacting numerous customers under loss of load approaching 1000 MW.
- Added Attachment G.12 NERC Standard FAC-002 – Facility Interconnection Studies to address FAC-002-4 Requirement R6 regarding the definition of Qualified Change to existing interconnections.

Revision 54 (07/26/2023):

- Updated references from TPL-001-4 to TPL-001-5.1.
- Revised Manual 14B language to align with updated requirements in TPL-001-5.1:
  - 2.3.11 Spare Equipment Strategy Review
  - H.1.2 Load Flow Modeling Requirements
- Updated Attachment I: Steady State & Stability Performance Planning Events table to align with TPL requirements

Revision 53 (07/26/2023):

- Introduction: Revised terminology to align with new tariff language, updated references
- Section 1A.3.1.1: Updated terminology
- Section 1.1: Updated terminology/references
- Section 1.4.1.6: Updated terminology/references
- Section 1.4.2.3: Updated terminology
- Section 1.4.3: Updated terminology
- Section 2.1.1.1: Updated terminology/references
- Section 2.1.2: Updated terminology
- Section 2.2: Updated terminology, revised note to clarify potential impact of generation retirements
- Section 2.3.1: Updated terminology
- Section 2.3.3: Updated terminology

- Section 2.4: Updated terminology/references, streamlined language
- Section 2.5: Updated reference
- Section 2.9: Format and terminology correction
- Attachment A, A.1: Updated reference
- Attachment A, A.2: Updated reference
- Attachment B, B.3: Updated terminology
- Attachment B, B.4: Updated terminology
- Attachment C, C.2.6: Updated terminology
- Attachment C, C.3.1.3: Updated terminology throughout, removed statement referencing serial queue process in step 2, and revised statement on commercial probability to align with IPRTF material in step 5a
- Attachment C, C.4: Updated terminology
- Attachment G, G.1: Updated terminology
- Attachment G, G.2.1: Updated terminology/references
- Attachment G, G.2.2: Updated terminology and stability language to align with current process
- Attachment G, G.3: Updated terminology
- Attachment G, G.3.1: Updated terminology/references
- Attachment G, G.3.2: Updated terminology/references and stability language to align with current process
- Attachment G, G.5: Updated terminology/references, and removed section G.5.1 – Wind Project Final Impact Study Data
- Attachment G, G.7: Updated reference
- Attachment G, G.9.1: Updated terminology and added reference to Transmission Owner Planning Criteria
- Attachment G, G.9.4: Addition of ComEd transient voltage recovery criteria
- Attachment H, H.1.2: Updated terminology
- Attachment H, H.1.4: Updated terminology
- Attachment H, H.1.5: Updated terminology

Revision 52 (4/10/2023):

- Updates to the Generator Deliverability Procedure to implement block dispatch
  - New Exhibit 4 – Block Dispatch for RTEP Cases
  - Section 2.3
  - Sections 2.3.11 (Light Load) and 2.3.13 (Winter Peak) removed, now addressed in 2.3.10

- Attachment B
- Attachment C.3
- Attachment D-1
- Attachment D-2 and D-3 removed, now addressed in C.3

- Section 1A.3.2 added to clarify PJM CEII Handling
- Added Attachment K: CIR for ELCC Transition

Administrative Change (01/21/2022):

- Updated manual ownership from Aaron Berner to Sami Abdulsalam

Revision 51 (12/15/2021):

- Changes to grammar in 1.3.2 Economic Planning
- Added a new subsection 1.4.2.4 Incorporation of EOL Needs into the RTEP
- Added new language detailing analysis in 2.1.2 Reliability Planning
- Added new graphics in 2.2.1 Reliability Planning
- Updated language to include Winter Peak Cases in 2.3.8 NERC P3 and P6 “N-1-1” Analysis
- Changed the title of subsection 2.3.15 to Extreme Event Review
- Added new objectives in 2.6 RTEP Market Efficiency Planning
- Added language in the following Attachments
  - B.2 and B.3
  - C.2.6
  - D.1
  - F
  - G.9.2 and G.9.6
  - H.1.2 and H.1.3

Revision 50 (07/01/2021):

- Added a new subsection 1.4.1.8 Maintaining reliability associated with critical substations
- Added a new bullet in section 2.1 Transmission Planning
- Added a new section 2.9 Critical Substation Planning Analysis

Revision 49 (06/23/2021):

- Changes to section 2.6 RTEP Market Efficiency Planning
  - Added Reliability Pricing Model constraints to the list of constraints that have an economic impact.

- Inserted new subsection 2.6.5.2 Determination of Reliability Pricing Model (RPM)Benefits in section 2.6.5 Determination of Market Benefits - RPM benefits are determined using RPM simulations for the RPM and RTEP years.

- Attachment E: Market Efficiency Analysis Economic Benefit / Cost Ratio Threshold Test
  - Updated obsolete language regarding the 15 year period used for the B/C ratio to conform to the B/C ratio changes, PJM OA Section 1.5.7, accepted by FERC Order Docket No. ER19-80-001) (Issued 2019-02-19)

Revision 48 (10/01/2020):

- Add metering systems to section B.3 Procedure RTEP Deliverables third Bullet

Revision 47 (09/01/2020):

- Updated sections G.3, G.4 and G.5 to incorporate the FERC Order 845 Second Compliance Filing Tariff changes.
- Clarified that stability analysis will be performed during the Facilities Study

Revision 46 (08/28/2019):

- Changes to section 2.6.8 Market Efficiency project reevaluation process

Revision 45 (08/22/2019):

- Conform changes for context and alignment of terms (multiple locations)
- Update links for PJM.com
- Section 1.1, 1.3.4:
  - Provide additional clarity as to the process of integrating Supplemental Projects in the RTEP
- Section 1.3:
  - Define the applicability of modeling requirements associated with the RTEP
- Section 1.4:
  - Update outline numbering
  - Conform discussions for Customer Funded Upgrades to the definitions and processes from the Tariff
- Section 1.4.2:
  - Clarify how overlapping needs are addressed in the RTEP
- Section 1.4.3:
  - Provide information as to the process used for the removal of projects from the RTEP under various conditions

Revision 44 (02/21/2019)

- Cover to Cover Periodic Review

- Revision to Section 1A on CEII
- Updated Attachment C
  - Various updates for clarity and alignment with current processes
  - Section C.2
    - Added language that non-radial facilities 345 kV and up will only automatically be considered as CETL limits for an LDA if they have greater than a 2% OTDF
    - Clarified that PJM may choose to include specific non-PJM transmission facilities in the load deliverability test in order to account for significant loop flows
    - Removed sentence that states that Load Deliverability Facility List will be locked down prior to each baseline
    - New procedure added to require both thermal and voltage analysis on both Discrete Outage Case and Mean Dispatch Case
    - Procedure modified to examine mean thermal loadings instead of median thermal loadings

Revision 43 (01/24/2019):

- Revise Section 1 and 2 to incorporate references to the Open Access Transmission Tariff, Attachment M-3 process
- Revise Sections 1 and 2 to include improved discussion of workflow and alignment to current processes

Revision 42 (08/23/2018):

- Updated Section 2.6.5 to include RTEP+15 b/c cap and for benefits adjustments due to in-service year later than RTEP. Also added language to note fixed generation and transmission topology for each simulation year.

Revision 41 (04/19/2018):

- Cover to Cover Periodic Review
- Updated Section 1.3 and Attachment H.1 per NERC MOD requirement standard numbering
- Updated Section 2.3.8 bullet formatting
- Updated Section 2.3.13 by removing language regarding winter temperature ratings sets
- Updated Attachment C.5.3.3 to add OVEC to study area definitions
- Updated Attachment C.7.3 to reference low side of transformer in generator deliverability procedures
- Updated Attachment D.2.2 to correct references to contingency types in table 2 and step 3

Administrative Change (01/31/2018):

- Manual ownership updated from Mark Sims to Aaron Berner

Revision 40 (10/26/2017):

- Updated Section 2.3.5 for bus tie breaker contingencies

Revision 39 (9/28/2017):

- Updates for termination of PJM/NYISO Wheel Agreement
- Updates to Attachment J(New Equipment Energization Checklist) for updated PJM Contact Department
- Updated Attachment G.7 for PJM Short Circuit model build contact

Revision 38 (07/27/2017):

- Removed references to the annual RTEP cycle in order to reflect the new 18-month RTEP cycle.
- Updated Exhibit 1 to also reflect new 18 month cycle.

Revision 37 (4/28/2017):

- Updated baseline thermal analysis section (2.3.6) to reflect correct N-1 analysis process
- Updated SPS to RAS per NERC definition change
- Updated PRC-023-3 to PRC-023 to account for future Standard revisions including PRC-023-4 which goes into effect 4/1/2017
- Updated for removal of EE (Energy Efficiency) References – as they are now included within the load forecast

Revision 36 (11/17/2016):

- Updated Attachment G.11 to reflect changes to Capacity Import Limit test as applicable to Long term Firm Service requests
- Updated hyperlinks throughout document to update for web changes

Administrative Change (10/01/2016):

- Attachment J:
  - Added hyperlinks for Training Series: Transition Planning, Modeling and Energization
  - Removed column entitled “Online Training Links”

Revision 35 (10/01/2016):

- Updated Section 2.3.13 and Attachment D-3.2 for ratings used in Winter Analysis
- New Appendix J: Checklist for New Equipment Energization Process and associated references in sections: 1.3.1; B.3; H.1; and H.1.3

Revision 34 (08/09/2016):

- Manual Ownership changed from Paul McGlynn to Mark Sims
- Added new Section 1A - About Critical Energy Infrastructure Information (CEII)

- Administrative Change: Updated Ramping Limits in winter peak study section
- Added Required In Service Dates for Light Load Reliability Analysis and Winter Peak Reliability Analysis
- Corrected references to TPL-001-4 in the PJM Planning SOL Methodology Section
- Updated Attachment G.9.6 including compliance language

Revision 33 (05/05/2016):

- Updated to revise Attachment G, Section 9.6.

Revision 32 (01/28/2016):

- Updated Attachment B, C and H for Transmission Service Study Procedures

Revision 31 (12/31/2015):

- Corrected references in C.5.7
- Updates to Section 2.1 for Multi Driver Approach
- Added a Winter Peak Reliability Analysis Criteria
- Updated section 2.7 for the inclusion of Energy Market Uplift
- Updates throughout this manual per TPL-001-4
- Periodic Review

Revision 30 (02/26/2015):

- Updated Section 2.3.13 to add more detail to the Long Term Deliverability Analysis
- Updated Attachment A to include a detailed cost allocation example
- Updated C.7 in Attachment C to add more detail to the Generator Deliverability Procedure
- Added C.8 in Attachment C to add more detail to the Long term Deliverability Analysis
- Updated G.2.2 to clarify the voltage drop test procedure
- Revision 29 (11/21/2014)
- Added “Modeling of Outages” section to Attachment H Section H.1.2
- Updated Section G.10 of Attachment for new version of PRC-023 standard

Revision 28 (08/21/2014):

- Added Section 4.8 to Attachment C for CETO/CETL as an input to RPM
- Updated Section numbering in Attachment C
- Updated Attachment A to reflect the current approved cost allocation methodology as described in the PJM OATT

Revision 27 (4/23/2014):

- Updated Attachment E for confirming changes associated with Market Efficiency Analysis and Benefit/Cost test

Revision 26 (3/28/2014):

- Updated Attachment C for changes to the use of commercial probability during the feasibility and impact study phases of the interconnection process
- Updated Attachment H for +2 year short circuit study cleanup
- Corrected typo/incomplete sentence in section G.4.1
- Added Section G.11: PJM Capacity Import Limit Calculation Procedure

Revision 25 (10/24/2013):

- Updated Attachment G.7 (Short Circuit) to a current year +2 short circuit planning representation
- Added confirming changes to Market Efficiency related to two year cycle process and timeline

Revision 24 (06/05/2013):

- Updated Attachment G.10 (PRC-023 – Transmission Relay Loadability)

Revision 23 (03/01/2013):

- Updated the Light Load Reliability Analysis Procedure
- Updated the SOL/IROL Definition in Planning to reflect inclusion of all PJM Markets Monitored facilities in alignment with PJM Operations
- Added Interim Updates and Communication of Significant Modeling Updates to Attachment H: Power System Modeling Data
- Correct typographical errors in section 2.3.3

Revision 22 (10/25/2012):

- Updated Exhibits for Base case development and 24 month cycle
- Addition of EKPC and Cleveland LDA, including Cleveland LDA map

Revision 21 (04/26/2012):

- Revised Generator Deliverability procedure to limit the “Adder” contribution based on an estimated CETO for generation in the receiving end area.

Revision 20 (12/22/2011):

- Added additional detail to the NERC Category C3 “N-1-1” section
- Created NERC Category C3 “N-1-1” stability section
- Added references to DUKE Energy Ohio/Kentucky

- Added additional detail to the NERC Standard PRC-023 Transmission Relay Loadability Section
- Updated Section 2 to reflect 24 Month Planning Process
- Fixed two small typos in the alt paragraph on P55 in the C.3 Section

Revision 19 (09/15/2011):

- Added Attachment H Power System Modeling Data

Revision 18 (7/20/2011):

- Added Light Load Reliability Analysis criteria and created a new attachment D-2 to contain the criteria.
- Added description of reactive load modeling in CETL base cases.

Revision 17 (4/13/2011):

- Added references where appropriate to reflect the inclusion of the American Transmission Systems, Inc. (ATSI) and Cleveland Public Power (CPP).
- Clarified the methodology to establish an IROL in the Planning Horizon.
- Updated the short circuit methodology to include the existing process to study all BES breakers.

Revision 16 (11/18/2010):

- Added a Contingency Definitions section (10/20/2010 MRC approval)
- Added Appendix G.10 NERC Standard PRC-023 – Transmission Relay Loadability (10/20/2010 MRC approval)
- Modified PJM Critical Energy Infrastructure Information Release Guidelines (08/05/2010 MRC approval)
- Added clarifying language to Baseline Voltage Analysis test methodology (08/05/2010 MRC approval)Updated the IROL definition to align with the latest NERC IROL definition (08/05/2010 MRC approval)

Revision 15 (04/21/2010):

- Added new Attachment F describing PJM stability, short circuit and special RTEP practices and procedures. This Attachment includes the special requirements for coordination of planning for nuclear interfaces

Revision 14 (02/01/2010):

- Attachment C: Added language to specify how energy efficiency is incorporated into deliverability tests. Added additional language to specify the load level modeled in the load deliverability test for the area being tested. (1/22/10 MRC Approval)

Revision 13 (11/16/2009):

- Inserted Commercial Probability technique in Attachment C, Generator Deliverability Procedure Step 5 (10/2/08 MRC approval)
- Added Attachment F: Determination of System Operating Limits for Planning the Bulk Electric System (06/17/09 MRC approval)
- Attachment C: Cap on generation delivery adders (12/21/09 MRC approval)
- Attachment C: Added language to Overview of Deliverability to Load to clarify criteria that may trigger analysis of potential new LDAs (11/11/09 MRC approval)
- Updated hyperlinks throughout the manual
- Temperature correction and clarification to Attachment B Section VII.N.

***Revision* 12 (08/08/2008):**

The following revisions primarily consist of additions, clarifications and reorganization to address FERC Order No. 890 requirements:

- Additions to Section 1 to update, clarify, and expand the RTEP overview.
- Combine old Sections 6 and 2 into an expanded Section 2.
- Move wind, power factor and behind the meter generation material to a reconstituted Section 6
- Include additional reliability planning process and criteria information
- Market Efficiency Process revisions (section 2 and Attachment E) plus additional editorial and consistency changes throughout including Attachments D, E, and G.
- Added Exhibit 1 edits to Intro, Sections 1, 2, related attachments
- Multiple passes of CEII revisions.
- Generation Delivery clarifications in Attachment C.
- Removed the final material in Section 2 that is related to Interconnections to Manual 14A and revised the remaining material appropriately for Manual 14B.
- Exhibit 1 update for quarterly queues
- Attachment D criteria clarifications
- Added final RPPWG comments of Nov 30, 2007 meeting, added minor clarifications, and cut material to move to the appropriate generation or transmission interconnection related portions of revised 14A and 14E as to be determined. Sections deleted from here and moved to either 14A or 14E are: (the following attachment designations are according to the previous version Manual 14B lettering)
- Moved Section 3: Generator and Transmission Interconnection Planning Process
- Generation and Transmission Interconnection Feasibility Study
- System Impact study
- Generation and Transmission Interconnection Facilities Study

- Moved Section 4: Small Resource Interconnection Process
- Moved Section 5: Interconnection Service, Construction & Other Service Agreements
- Moved Section 6: Additional Generator Requirements
- Behind The Meter Generation Projects
- Generator Power Factor Requirements
- Wind-Powered Generation Projects
- Moved Attachment A: PJM Generation and Transmission Interconnection Planning Process Flow
- Attachment B: PJM Cost Allocation Procedures
- Moved PART 1: PJM GENERATION AND TRANSMISSION INTERCONNECTION COST ALLOCATION
- Moved Attachment C : PJM Generation and Transmission Interconnection Planning Team Role Diagram
- Moved Attachment F: General Description of Facilities Study Procedure
- Moved Attachment H: Small Generator (10 MW and Below) Technical Requirements and Standard
- Moved Attachment H-1: Small Generator (above 10 MW to 20 MW) Technical Requirements and Standards
- Moved Annex 1: SCADA Requirements by Transmission Owner Region

Revision 11 (10/05/2007):

- The Manual Title has been changed. The RTEP process has evolved over the past 5+ years and so has the scope of Manual 14B. The title of the manual has been changed from "Generation and Transmission Interconnection Planning" to "PJM Regional Planning Process"
- Section 6 and Attachment I have been revised to reflect the implementation of the 15-year horizon component of PJM's Regional Planning Process cycle, including that for market efficiency. These changes are made in accordance with the mmm, dd 2006 FERC approval of PJM's subject Operating Agreement and Open Access Transmission Tariff (OATT) revisions.
- Conforming editorial revisions have been made throughout the remainder of the document.

Revision 10 (03/01/2007):

- Attachment B: Regional Transmission Expansion Plan revised to include steps for reactive planning in the RTEP.
- Revised hyperlinks in Attachment D: PJM Reliability Planning Criteria.
- Attachment H: Small Generator (10 MW and Below) Technical Requirements and Standards replaces former attachment on Small Generators of 2 MW and less.

- Attachment H-1: Small Generator (above 10 MW to 20 MW) Technical Requirements and Standards added.
- References to PJM OATT provisions in Sections 2 and 5 are revised to indicate that they are now in the new Part VI of the OATT (along with their former Part IV locations)
- Wording in Section 2 under “Summary of RTEPProcess” and again in Attachment E is revised to reflect that generation retirements included in project studies will be those announced as of the date a project enters the project queue.
- Introduction trimmed to eliminate redundant information.
- List of PJM Manuals exhibit removed, with directions given to PJM Web site where all the manuals can be found.
- Revision History permanently moved to the end of the manual.

Revision 09 (06/07/06):

- Manual sections 1 and 2 and Attachment B (Regional Transmission Expansion Plan – Scope and Procedure) are revised to include Probability Risk Analysis (PRA) of Aging Infrastructure as an input to the PJM Region transmission planning process. The timeline in Section 5 is revised to require the Transmission Owner to submit a final invoice to PJM within 120 days after project completion. Attachment B (Regional Transmission Expansion Plan – Scope and Procedure) is also revised to add guidelines for Scenario Planning. Replaced references throughout to “ECAR, MAAC and MAIN” with ReliabilityFirst, the new replacement regional reliability council as of January 1, 2006.
- Revisions were made on the following pages: 8, 10, 12 through 16, 23, 24, 41, 56, 62, 63, 65, 67, 68 and 98.

Revision 08 (01/16/06):

- Section 1 is revised to state that all analyses of Transmission System adequacy are conducted using the load forecast produced annually by PJM. Attachments E and G are revised to state that load is modeled in the RTEP base case used for the Generator Deliverability procedure at a “non-diversified” 50/50 summer peak load level as per the latest load forecast.

Revision 07 (01/04/06):

- Section 2 is revised to add process for “Evaluation of Operational Performance Issues.” Attachment A is revised to clarify the Load Flow Cost Allocation Method and to add the Schedule 12 Cost Allocation process. Attachment C is revised to include references to Dominion and to add Addendum 2 “Common Mode Outage Procedure” to the Generator Deliverability Procedure. Attachment D is revised to include a minimum power factor for system “load”.

Revision 06 (11/21/05):

- Section 2 is revised to indicate that “One RTEP baseline regional plan will be developed and approved each year” and that “Generation retirements will not affect the study results” for any project that has received an Impact Study Report. Attachment B is revised to clarify and expand the scope and procedure of the Regional Transmission Expansion Planning Process.

Revision 05 (06/23/05):

- Revision includes a change in Section 6 to include reference to new Attachment E, re-writes of Attachment C (PJM Deliverability Testing Methods) and Attachment D (PJM Reliability Planning Criteria) and the addition of new Attachment E (Economic Planning Process, Congestion Relief Evaluation).

Revision 04 (12/17/04):

- Revision includes the changes in Sections 2 and 4 necessitated for compliance with FERC Order 2003 for standardized Generator Interconnection Agreements and Procedures, re-write of Attachment F: Facilities Study Guidelines, re-write of Attachment D: PJM Reliability Planning Criteria, and the addition of Attachment H: Small Generator (2MW or less) Technical Requirements and Standards.

Revision 03 (06/08/04):

- Revision includes the addition of rules for Generator Power Factor Requirements and Behind the Meter Generation in Section 2, the designation of small resources as 20 MW or less in Section 4, the addition of the Economic Planning Process in Section 6 and general updates.

Revision 02 (10/31/03):

- Revision includes the addition of Wind-Powered Generator Specific Requirements to Section 2, a placeholder for the addition of the Economic Planning Process in new Section 6 (currently under development) and the addition of Attachments D (Regional Transmission Expansion Plan – Scope and Procedure), E (PJM Deliverability Testing Methods), F (General Description of Facilities Study Procedure) and G (PJM Reliability Planning Criteria); also, text changes throughout to conform with Nuclear Plant Licensee Final Safety Analysis Report grid requirements and with new Manual M-14E (Merchant Transmission Specific Requirements – also currently under development).

Revision 01 (02/26/03):

- Revision includes a manual title change from PJM Manual for Generation Interconnection Transmission Planning (M-14B) to PJM Manual for Generation and Transmission Interconnection Planning (M-14B); also, text changes throughout to conform to new Manuals M-14C and M-14D.

Revision 00 (12/18/02):

- This document is the initial release of the PJM Manual for Generation Interconnection Transmission Planning (M-14B).
- Manual M-14, Revision 01 (03/03/01) has been restructured to create five new manuals:
- M-14A: “Generation Interconnection Process Overview”
- M-14B: “Generation Interconnection Transmission Planning”
- M-14C: “Generation Interconnection Facility Construction”
- M-14D: “Generation Operational Requirements”
- M-14E: “Merchant Transmission Specific Requirements”

EXHIBIT NO. 53

PJM RTEP - 2022 RTEP PROPOSAL WINDOW #3

PROBLEM STATEMENT & REQUIREMENTS

Document Scope: 2027-28 Summer Reliability Analysis; 2027-28 Winter Reliability Analysis; 2027-28 Light Load Reliability Analysis; 2027-28 Short Circuit Analysis

2022 RTEP PROPOSAL WINDOW #3

Purpose of Proposal Window

PJM seeks technical solutions, also called proposals, to resolve potential reliability criteria violations on facilities identified below in accordance with all applicable planning criteria (PJM, NERC, SERC, RFC, and Local Transmission Owner criteria).

Criterion Applied by PJM for this Proposal Window

- 2027-28 Summer

  Baseline Thermal and Voltage N-1 Contingency Analysis

  Generator Deliverability and Common Mode Reliability Analysis

  N-1-1 Thermal and Voltage Analysis and Voltage Collapse

  Load Deliverability Thermal and Voltage Analysis

  Dynamic Stability Assessment

- 2027-28 Winter

  Baseline Thermal and Voltage N-1 Contingency Analysis

  Generator Deliverability and Common Mode Reliability Analysis

  N-1-1 Thermal and Voltage Analysis and Voltage Collapse

  Load Deliverability Thermal and Voltage Analysis

  Dynamic Stability Assessment

- 2027-28 Light Load*

  Baseline Thermal and Voltage N-1 Contingency Analysis

  Generator Deliverability and Common Mode Reliability Analysis

  *PJM aims to provide the Light Load cases early in March 2023, on or before March 6th.

Terminology for Proposal Windows

Through the analyses listed above, PJM has compiled a list of criteria violations. The violations and the impacted facilities are identified by a table of flowgates. Descriptions of the column headings are provided below. Different analyses often use different column headings.

Typical thermal analysis column headings:

Column Heading	Title	Description
FG #	Flowgate Number	A sequential numbering of the identified potential violations
Fr Bus	From Bus Number	PSSE model bus number corresponding to one end of line identified as a potential violation
Fr Name	From Bus Name	PSSE model bus name corresponding to one end of line identified as a potential violation
To Bus	To Bus Number	PSSE model bus number corresponding to other end of line identified as a potential violation
To Name	To Bus Name	PSSE model bus name corresponding to other end of line identified as a potential violation
Monitored Facility	Monitored Facility	The circuit on which a potential violation is occurring
Base Rate (MVA)	Base Rate (MVA)	Normal Facility Rating (Rate A)
% Overload	Percentage Overload	Percentage above corresponding Facility Rating
CKT	Circuit ID	Circuit number of identified potential violation
KVs	Kilovolt level (A/B)	Kilovolt level of both sides of potential violation, if A does not equal B, potential violation is a transformer
Areas	Area Numbers (A/B)	Area numbers of both ends of potential violation (A=From Bus Area Number, B=To Bus Area Number) If A does not equal B, potential violation is a tie line
Rating	Facility Rating	Applicable thermal rating (MVA) of facility
DC Ld(%)	Direct Current Loading percentage	Percentage above Facility Rating determined from DC testing
AC Ld(%)	Alternating Current Loading percentage	Percentage above Facility Rating determined from AC testing
Cont Type	Contingency Type	Contingency categorization (e.g., Single, Bus, Line_FB, Tower)
Cont Name	Contingency Name	Contingency name as identified in associated contingency file or embedded in the spreadsheet

Contingency	Contingency	Contingency description
Violation Date	Violation Date	Date on which violation is expected to occur
Analysis Case	Analysis Case	Case title to use in replicating analysis

Typical voltage analysis column headings:

Column Heading	Title	Description
FG #	Flowgate Number	A sequential numbering of the identified potential violations
Bus #	Bus Number	PSSE model bus number corresponding to bus identified as a potential violation
KVs	Kilovolt level	Kilovolt level of bus identified as potential violation
Area	Area Number	Area number of bus identified as potential violation
ContVolt	Contingency Voltage (P.U.)	Per Unit Voltage at identified bus after contingency is applied
BaseVolt	Basecase Voltage (P.U.)	Per Unit Voltage at identified bus before contingency is applied
Low Limit	Low Voltage Limit(P.U.)	Threshold of Per Unit Low voltage, if ContVolt is under this limit, a potential violation is identified
Upper Limit	High Voltage Limit(P.U.)	Threshold of Per Unit High voltage, if ContVolt is over this limit, a potential violation is identified
Cont Type	Contingency Type	Contingency categorization (e.g., Single, Bus, Line_FB, Tower)
Vdrop (%)	Voltage drop	The percentage that the voltage has dropped as a result of the contingency
Contingency	Contingency	Contingency name as identified in associated contingency file
Contingency 1	First Contingency	N-1 (first) contingency identified
Contingency 2	Second Contingency	N-1-1 (second) contingency identified in N-1-1 analysis

Proposal Window Exclusion Definitions

The following definitions explain the basis for excluding flowgates from the competitive planning process and designating projects to the incumbent Transmission Owner.

Flowgates excluded from competition will include the underlined language in the comment field.

- Immediate Need Exclusion: For immediate reliability needs that must be addressed within three years or less and for which PJM determines a proposal window may not be feasible , these reliability violations are excluded from the competitive proposal window process. As a result, the local Transmission Owner will be the Designated Entity. Refer to Operating Agreement, Schedule 6 § 1.5.8(m)
- Below 200kV Exclusion: Due to the lower voltage level of the identified violations, these reliability violations are excluded from the competitive proposal window process. As a result, the local Transmission Owner will be the Designated Entity. Refer to Operating Agreement, Schedule 6 § 1.5.8(n)
- Substation Equipment Exclusion: For reliability violations on existing transmission substation equipment, these reliability violations are excluded from the competitive proposal window process. As a result, the local Transmission Owner will be the Designated Entity. Refer Operating Agreement, Schedule 6 § 1.5.8(p). Please note that some flowgates are substation equipment limited, eligible for exclusion but were still included in the competitive window. Since these flowgates are in the cluster of a group of violations, PJM provided these in the window for visibility and consideration part of the window proposal package.
- Supplemental Projects scope: These cover violations to be addressed through supplemental solutions, primarily to address 300 MW load loss criteria due to preliminary allocation of load.
- Areas external to the study area that will be covered part of upcoming 2023 RTEP: These cover violations identified in the basecase extensively remote from the study area within ATSI, ComEd and AEP zones). These violations are not associated with eth Data Center Loads increase in APS and Dominion zones and will be covered part of the upcoming 2023 RTEP.

Analysis Procedure

Participants are expected to develop solutions to the identified criteria violations and perform analysis to validate that the solutions remove these violations identified under the 2027-28 baseline cases. The competitive planning process is documented in PJM Manual 14F, which is available here: http://www.pjm.com/-/media/documents/manuals/m14f.ashx

Proposed solutions must also meet Transmission Owner Planning Criteria which is available here: http://www.pjm.com/planning/planning-criteria/to-planning-criteria.aspx

Although PJM does its best to provide complete and accurate results, changes to the list of violations under consideration are possible. That is, flowgates may be added or removed from consideration in the proposal window. PJM works with Transmission Owners, Generation Owners, neighboring TOs and other affected parties to verify the quality of the analysis. PJM endeavors to minimize such changes and will clearly communicate any changes to the participants.

PJM regularly updates the system model to reflect changes to the transmission system. Analyses are performed to verify that violations continue to be valid, no new violations have appeared and proposed solutions still address the targeted violation(s).

PJM shall determine the more efficient or cost-effective enhancements or expansions for any violation.

Scope of Work

PJM is seeking proposals to resolve identified reliability criteria violations associated with data center load growth in the Dominion and APS (FirstEnergy) service territories.

OBJECTIVES:

1. Develop robust, holistic and expandable solutions that address the 2027-28 baseline violations associated with:
    a. Local constraints which are constraints resulting from directly serving the data center loads in APS and Dominion zones through the respective 230 kV networks and into the points of delivery. Examples include reinforcements to transmission path segments:
        i. Goose Creek- Ashburn – Mars - Wishing Star and Brambleton

    b. Regional constraints resulting from imports into load center areas to serve data center loads. These primarily cover the following 500 kV transmission paths (together with their paralleling 230 kV circuits):
        i. Doubs - Goose Creek
        ii. Front Royal - Morrisville – Vint Hill – Loudoun/Mosby
        iii. Meadow Brook - Loudoun/Mosby
        iv. Morrisville – Bristers - Ox
        v. Peach Bottom – Conastone – Brighton – Doubs

    c. Needed reactive power VAR reinforcements, both static and dynamic as deemed necessary, to address the reactive power needs of the system for the 2027-28 baseline scenario

2. Develop solutions to address all (if any) new criteria violations generated as a consequence of proposed solution. Solutions to these secondary violations are required for the proposal to be considered.

3. Adhere to all applicable planning criteria, including PJM, NERC, SERC, RFC and Local Transmission Owner Criteria.

REQUIREMENTS:

- Holistic solutions are to be designed such that they are robust and expandable as the load grows within the area. A scalable solution ensures, at a minimum, near-term reliability needs are addressed while also enabling future expansion (beyond the 2027-28 baseline levels) as data center load increases in the Dominion and APS zones.

    - Consider flexibility, robustness and scalability of 2027-28-baseline solutions against the Interim 2027-28 Summer, Winter and Light Load basecases.
    - Evaluate proposals for their effectiveness towards existing reactive interfaces in the area, particularly those supporting the Dominion and APS zones.
    - Evaluate the effectiveness of the proposed solutions towards the transmission system load deliverability into the Dominion and APS zones (CETL).

ASSUMPTIONS:

- Preliminary Reactive Support:
  - The provided 2027-28 basecases include a set of reactive VAR support at existing/proposed substations to partially meet the system reactive load demand particularly under system normal, N-0 conditions.
  - These preliminary reactive VAR support reinforcements are already provided at specific locations as indicated in Table 1.a and Table 1.b. They are further detailed through the VAR support inclusion IDEVs part of the 2022 RTEP Window 3 modeling files.
  - The preliminary VAR support included in the basecases do not imply final VAR level, type or location. The assumed VAR support levels were only adequate for need analysis purposes. These Temporary VAR support measures in the case(s) should be removed and replaced consistent with an entities proposal to provide the necessary VAR support. The preliminary VAR support should not be relied upon as part of the proposal.
  - PJM expects that proposals will provide for the needed reactive VAR support through either transmission development or static/dynamic VAR support devices or a combination of both.
  - There are a number of non-convergent contingencies due to deficient VAR support and excessive reactive power loss in the 2027-28 modeling basecases.
  - Based on the preliminary VAR resource assumptions in the cases, the provided voltage performance results are for guiding purposes only. Proposal developers are to re-evaluate the voltage performance part of their proposal development to ensure compliance with voltage performance requirements.
- Basecase N-0 thermal Violations:
  - The 2027-28 baseline case(s) show thermal violations along the Peach Bottom-Conastone and Conastone-Brighton 500kV paths.
  - These 500 kV segments are also showing marginal overloads approaching 98% to 100% under N-1 conditions for the baseline summer conditions.
- Non-Converged N-1 Contingencies:
  - A number of key non-convergent N-1 contingencies are provided in Table 2. These contingencies lead to voltage collapse on the 500kV system due to insufficient transmission system transfer capability and VAR support inadequacy.
  - Following development of VAR support enhancements, thermal loading on all system elements needs to be monitored and overloads, if any, need to be addressed part of the proposed solutions.
- N-1-1 Analysis;
  - Due to the significant load growth presented in the baseline 2027-28 basecases, a large number of N-1-1 contingencies lead to unsolvable security constraint redispatch conditions. Hence, the provided N-1-1 results are to be revaluated as part of the proposal solution development process.
  - PJM aims provide the interim 2027-28 basecase N-1-1 results by early March and no later than March 6th 2023 on the PJM website in the competitive planning section.
- Load Deliverability analysis:
  - PJM requires the proposed solutions are evaluated for their effectiveness towards load deliverability into the APS and Dominion zones.
  - PJM will provide the load deliverability modeling instructions and parameters during the week of March 6th.

Table 1.a 2027-28 Baseline - Preliminary Reactive VAR support (to be replaced by 2022 RTEP Window 3 Proposals)

Station	kV	MVAR
Barrister	230	300
Stratus	230	150
Prentice	230	150
Mars 500kV	500	150
Mars 500kV	500	150
Wishing Star 500 kV	500	150
Wishing Star 500 kV	500	150
Winters Branch	230	150
Winters Branch	230	150
Rixlew	230	150
Rixlew	230	150
Ocean Court	230	150
Ocean Court	230	150
Rollings Ford	230	150
Rollings Ford	230	150
Kyser	230	150
Nimbus	230	150
Nimbus	230	150
DTC	230	150
Pleasant View 500kV	230	300
Spotsylvania 500kV	500	300
Loudoun 500kV	500	300
Wakefield	230	150
Wakefield	230	150
Dawkins Branch	230	150
Youngs Branch	230	150
Total		**4500**

Table 1.b 2027-28 Intermediate - Preliminary Reactive VAR support (to be replaced by 2022 RTEP Window 3 Proposals)

Station	kV	MVAR
Barrister	230	150
Dawkins Branch	230	150
Youngs Branch	230	150
DTC	230	150
Stratus	230	150
Mars	500	150
Wishing star	500	294
Ocean Court	230	150

Station	kV	MVAR
Ocean Court	230	150
Total		**1494**

Table 2 2027-28 Baseline Summer Non-Convergent Contingencies

Contingency Name	Cont. Type	Analysis Type	Error Type
AP_P1-2_PE-500-001_SRT-SL	Single	Voltage Drop	Blown Up
AP_P1-2_WP-500-DRT17_SRT-SL	Single	Voltage Drop	Blown Up
PJM_500_BG_P1_5011_SRT-A	Single	Voltage Drop	Blown Up
AP_P2-3_PE-500-015_SRT-A	Line_FB	Voltage Drop	Blown Up
AP_P2-3_PE-500-016_SRT-SL	Line_FB	Voltage Drop	Blown Up
AP_P2-3_PE-500-018C_SRT-SL	Line_FB	Voltage Drop	Blown Up
AP_P2-3_PE-500-018D_SRT-SL	Line_FB	Voltage Drop	Blown Up
AP_P2-3_PE-500-019D_SRT-SL	Line_FB	Voltage Drop	Blown Up

WHAT PJM PROVIDES:

The information listed below is provided to allow replication of PJM analyses. Some of this data is designated Critical Energy Infrastructure Information (CEII) and must be handled consistent with PJM's CEII request process at Competitive Planning Process page on the PJM website:

1. Power Flow Base Cases. Identifies one or more system configurations to which planning criteria are applied.
2. Contingency List: Lists all contingency types (single, bus, tower, line w/ stuck breaker).
3. Subsystem Files: Identifies all subsystem zones to be considered in analysis.
4. Monitor Files: Identify specific ranges of facilities by area and kV level to be considered in analysis.
5. Facility Ratings: (if different from those included in the base cases)
6. Violations List: Lists all criteria violations with power flow results and additional technical notes (flowgates). The results indicate the case(s) to which the criteria violations apply.
7. Short Circuit Base Case. This case reflects the 2027-28 RTEP base case.
8. Breaker Change Files. Lists all over-duty breakers in a specific TO area.
9. TO Criteria Setting Files. Lists settings used for short circuit analysis for each specific TO.
10. TARA Generation Deliverability options files.
11. Generator Data files used in Generation Deliverability tests
12. Dynamic modeling files for dynamic stability assessments (to be provided during the week of March 6th 2023).

Response Back To PJM (Deliverables)

This section describes the required elements of a complete proposal. The absence of any element renders the proposal incomplete and the proposal will not be considered for selection.

Often there are several viable solutions to a given violation. Include alternate approaches in separate proposals. PJM will not accept proposals with multiple options.

Four categories of information are described below: three are required for a complete package and one is conditional.

- Technical analysis files and documentation
- Completed proposal submittal template
- Project diagrams
- Company evaluation and operations and maintenance information (if required)

Technical Analysis Files and Documentation

Include the following technical information to provide a complete project proposal package:

1. A detailed analysis spreadsheet showing the planning analysis results for the project.
2. A set of updates to the power flow cases which model the proposed solution. Provide files in a format compatible with PSS/E version 34.7. Provide only solvable and convergent solutions. Include an idv, or equivalent type, file in order to apply changes to other models. Assign a unique identifier when new busses are required. Provide contingencies in a single file for each contingency type. Organize the contingencies into one of three categories:
    a. Modified Contingencies
    b. New Contingencies
    c. Deleted Contingencies
3. List of all proposed equipment along with relevant parameters and assumptions.
    a. All necessary parameters, e.g., equipment ratings, impedances, line lengths, etc.
    b. For reactive devices, settings and outputs
    c. For synchronous machines, MW and MVAR output assumptions
4. An analysis report of proposed solution which identifies the issues being addressed.
5. Additional documentation required to verify the proposal.

PJM Proposal Submittal

The PJM Competitive Planner Tool is used for proposal(s) submittal and captures project details, such as the criteria violations or system constraints that are being targeted by the proposed solution, the overall and specific project descriptions and the details of cost commitment, if included. The Competitive Planner Tool and user guide are available on the Competitive Planning Process page: https://www.pjm.com/planning/competitive-planning-process.aspx.

All proposals will be made public and posted on pjm.com after the proposal window is closed. Mark all CEII and business confidential information for redaction from this public posting. Redact only information which meets the criteria of CEII or business proprietary and confidential information.

Redaction guidelines can be found in PJM Manual 14F, Section 6.2. Please note that this section provides guidance only. PJM reserves the right to challenge proposed redaction of information in order to ensure the appropriate level of transparency.

Project Diagrams

Provide project diagrams in the PJM Competitive Planner Tool to detail how the proposed solution will modify existing infrastructure, how new infrastructure will be configured and where new infrastructure will be sited. Project diagrams should include, but are not limited to, the following detail:

- Single line diagrams
- Substation general arrangement and station layout. If expanding the substation, identify the following:
  - Area to be modified
  - Land ownership or acquisition plan
- Line routing diagram:
  - Identify proposed route of new or upgraded transmission lines
  - Clearly identify where acquisition of additional right-of-way is required
- Detailed project schedule. Include, at minimum, the following major work activities:
  - Engineering and Design
  - Siting and Permitting
  - ROW and Land acquisition
  - Material procurement
  - Construction
  - Testing/Commissioning

Company Evaluation and Operations and Maintenance Information

For proposers seeking Designated Entity status, provide additional information which will aid PJM in understanding how the proposed solution will be developed, constructed, operated and maintained. Include this information in the PJM Competitive Planner Tool.

Relevant PJM Operating Agreement, Schedule 6, section 1.5.8(f).

Entity-Specific Criteria Considered in Determining the Designated Entity for a Project. In determining whether the entity proposing a Short-term Project, Long-lead Project or Economic-based Enhancement or Expansion recommended for inclusion in the plan shall be the Designated Entity, the Office of the Interconnection shall consider: (i) whether in its proposal, the entity indicated its intent to be the Designated Entity; (ii) whether the entity is

pre-qualified to be a Designated Entity pursuant to Operating Agreement, Schedule 6, section 1.5.8(a); (iii) information provided either in the proposing entity's submission pursuant to the Operating Agreement, Schedule 6, section 1.5.8(a) or 1.5.8(c)(2) relative to the specific proposed project that demonstrates: (1) the technical and engineering experience of the entity or its affiliate, partner, or parent company, including its previous record regarding construction, maintenance, and operation of transmission facilities relative to the project proposed; (2) ability of the entity or its affiliate, partner, or parent company to construct, maintain, and operate transmission facilities, as proposed, (3) capability of the entity to adhere to standardized construction, maintenance, and operating practices, including the capability for emergency response and restoration of damaged equipment; (4) experience of the entity in acquiring rights of way; (5) evidence of the ability of the entity, its affiliate, partner, or parent company to secure a financial commitment from an approved financial institution(s) agreeing to finance the construction, operation, and maintenance of the project, if it is accepted into the recommended plan; and (iv) any other factors that may be relevant to the proposed project, including but not limited to whether the proposal includes the entity's previously designated project(s) included in the plan.

Transmittal of Proposals

Proposal submissions along with all files required for submission will be done with the PJM Competitive Planner Tool for each submitted proposal.

Proposal Fees

All proposals, upgrade and greenfield solutions, with the exception of solutions submitted with an estimated cost of $5M or less, submitted for consideration in the 2022 RTEP Proposal Window 3 are subject to an initial $5,000 deposit per the PJM Operating Agreement 1.5.8(c).

Relevant PJM Operating Agreement language in Section 1.5.8(c):

(c)(1) All proposals submitted in the proposal windows must contain: (i) the name and address of the proposing entity; (ii) a statement whether the entity intends to be the Designated Entity for the proposed project; (iii) the location of proposed project, including source and sink, if applicable; (iv) relevant engineering studies, and other relevant information as described in the PJM Manuals pertaining to the proposed project; (v) a proposed initial construction schedule including projected dates on which needed permits are required to be obtained in order to meet the required in-service date; (vi) cost estimates and analyses that provide sufficient detail for the Office of Interconnection to review and analyze the proposed cost of the project; and (vii) with the exception of project proposals submitted with cost estimates of $5 million or less, a $5,000 non-refundable deposit must be included with each project proposal submitted by a proposing entity that indicates an intention to be the Designated Entity.

(c)(1)(i) In addition, any proposing entity indicating its intention to be the Designated Entity will be responsible for and must pay all actual costs incurred by the Transmission Provider to evaluate the submitted project proposal. To the extent the Transmission Provider incurs costs to evaluate multiple submitted project proposals where such costs are not severable by individual project proposal, the Transmission Provider shall invoice equal shares of the non-severable costs among the project proposals that cause such non-severable costs to be incurred. Notwithstanding this method of invoicing non-severable costs, non-severable costs will be jointly and severally owed by the proposing entities that cause such costs to be incurred.

(c)(1)(ii) All non-refundable deposits will be credited towards the actual costs incurred by the Transmission Provider as a result of the evaluation of a submitted project proposal.

(c)(1)(iii) Following the close of a proposal window but before the Transmission Provider incurs any third-party consultant work costs to evaluate a submitted project proposal, the Transmission Provider will issue to the proposing entity an initial invoice seeking payment of estimated costs to evaluate each submitted project proposal. The estimated costs will be determined by considering the: potential cost of consultant work, historical estimates for project proposals of similar scope, complexity and nature of the need, and/or technology and nature of the project proposal. The Transmission Provider may issue additional invoices to the proposing entity prior to the completion of the evaluation activities associated with a project proposal if the Transmission Provider receives updated actual cost information and/or upon consideration of the factors specified in this section.

(c)(1)(iv) At the completion of the evaluation activities associated with a project proposal, the Transmission Provider will reconcile the actual costs with monies paid and, to the extent necessary, issue either a final invoice or refund.

(c)(1)(v) The proposing party must pay any invoiced costs within fifteen (15) calendar days of the Transmission Provider sending the invoice to the proposing entity or its agent. For good cause shown, this fifteen (15) calendar day time period may be extended by the Transmission Provider. If the proposing entity fails to pay any invoice within the time period specified and/or extended by the Transmission Provider in accordance with this section, the proposing entity's pre-qualification status may be suspended and the proposing entity will be ineligible to be a Designated Entity for any projects that do not yet have an executed Designated Entity Agreement. Such a suspension and/or ineligibility will remain in place until the proposing entity pays in full all outstanding monies owed to the Transmission Provider as a result of the evaluation of the proposing entity's project proposal(s).

The non-refundable deposit is due at the time of submission. Pay the non-refundable deposit by wire transfer to PJM Interconnection at:

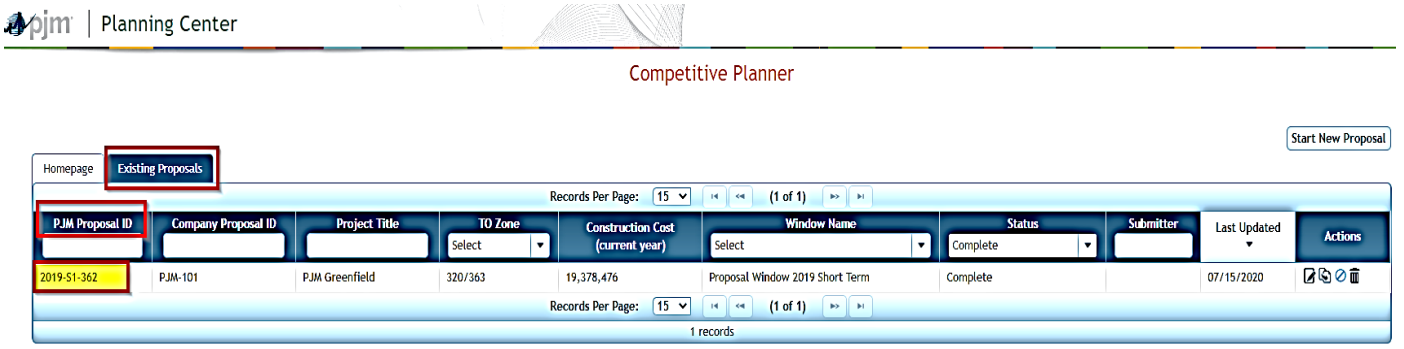
Wire transfer funds to:	PJM Interconnection, LLC
Bank Name:	PNC Bank, N.A. New Jersey
ABA Number:	031207607 (Fed Wire and ACH)
Account Number:	80-1358-9826
Provide Reference*:	Order 1000

To ensure the non-refundable deposit is properly accounted for, include a reference to "Order 1000 – Competitive submittal PJM Id ###" in the subject, notes or addenda field of the wire transfer form. Please note that the PJM ID ### will be displayed on the confirmation email you receive after submitting the proposal and is also identified on the competitive planner tool once a competitive proposal is initially saved.

The proposer also needs to provide the following information to PJM:

Company Info, Primary contact name, Billing email & Tax ID#.

The PJM Proposal ID can be located on the Existing Proposal screen in the PJM Competitive Planner Tool



Timeline

2/24/2023: Opening of 2022 RTEP Proposal Window 3

4/25/2023: Close of 2022 RTEP Proposal Window 3 at 11:59 p.m. Eastern Daylight Time

Notes:

- Confidentiality of individual proposals will be maintained for the duration of the window.
- Proposals received after close of the proposal window will not be accepted.

Questions

Submit all questions about the proposal window to the PJM Planning Community. Submit questions involving confidential information or CEII under the "Confidential" topic on the Planning Community. Answers will be provided to all participants in the proposal window.

Please reference 2022 RTEP Proposal Window 3 in all correspondence.

Specialized Requirements

PJM seeks proposals to evaluate the identified needs in this window. PJM has not determined specialized requirements that PJM is seeking in project proposals in this window for consideration in its evaluation.

Notice

In accordance with the Open Access Transmission Tariff, Attachment M, the MMU has access to all data submitted to PJM through PJM's competitive proposal window process. See Manual 14F, section 8.4.4.

Document Revision History

02/24/2023 - V1 - Original Problem Statement posted to the PJM Competitive Planning Process webpage: https://www.pjm.com/planning/competitive-planning-process.aspx.

EXHIBIT NO. 54

2023 RTEP 2028 Preliminary Summer & Winter Gen Deliv 500KV and above Violation Summary

Sami Abdulsalam
Wenzheng Qiu
Nebiat Tesfa

PJM©2022

Purpose

- Summarize bulk transfer needs identified in the 2028 RTEP
- Summarize changes in the 2028 RTEP models impacting earlier and newly identified needs.
- Discuss how the 2028 RTEP needs may influence solutions to the 2027 RTEP Window 3.
- Focus on bulk transfer needs:
  - Vast majority of relevant overlapping needs are due to bulk transmission constraints for regional transfers.

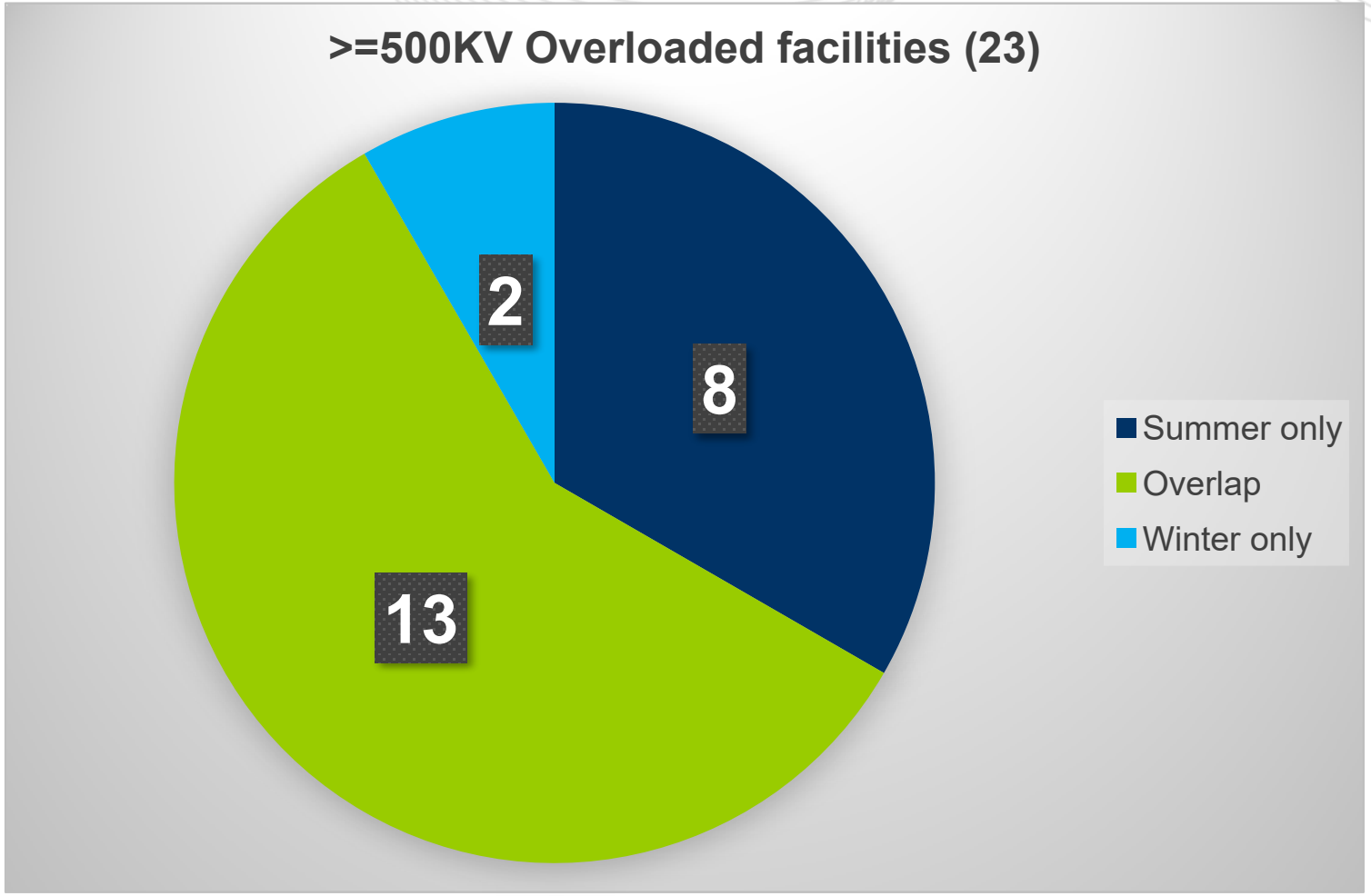
PJM©2023

What's new in the 2028 RTEP Models?

- 2023 Load Forecast
- Implementation of New Planning Methodology:
  - Generation Block Dispatch (Area transfer limits considerations)
  - Generation Deliverability Testing Requirements
- Recent Major Generation Retirements
- NJ Offshore Wind (Partial)

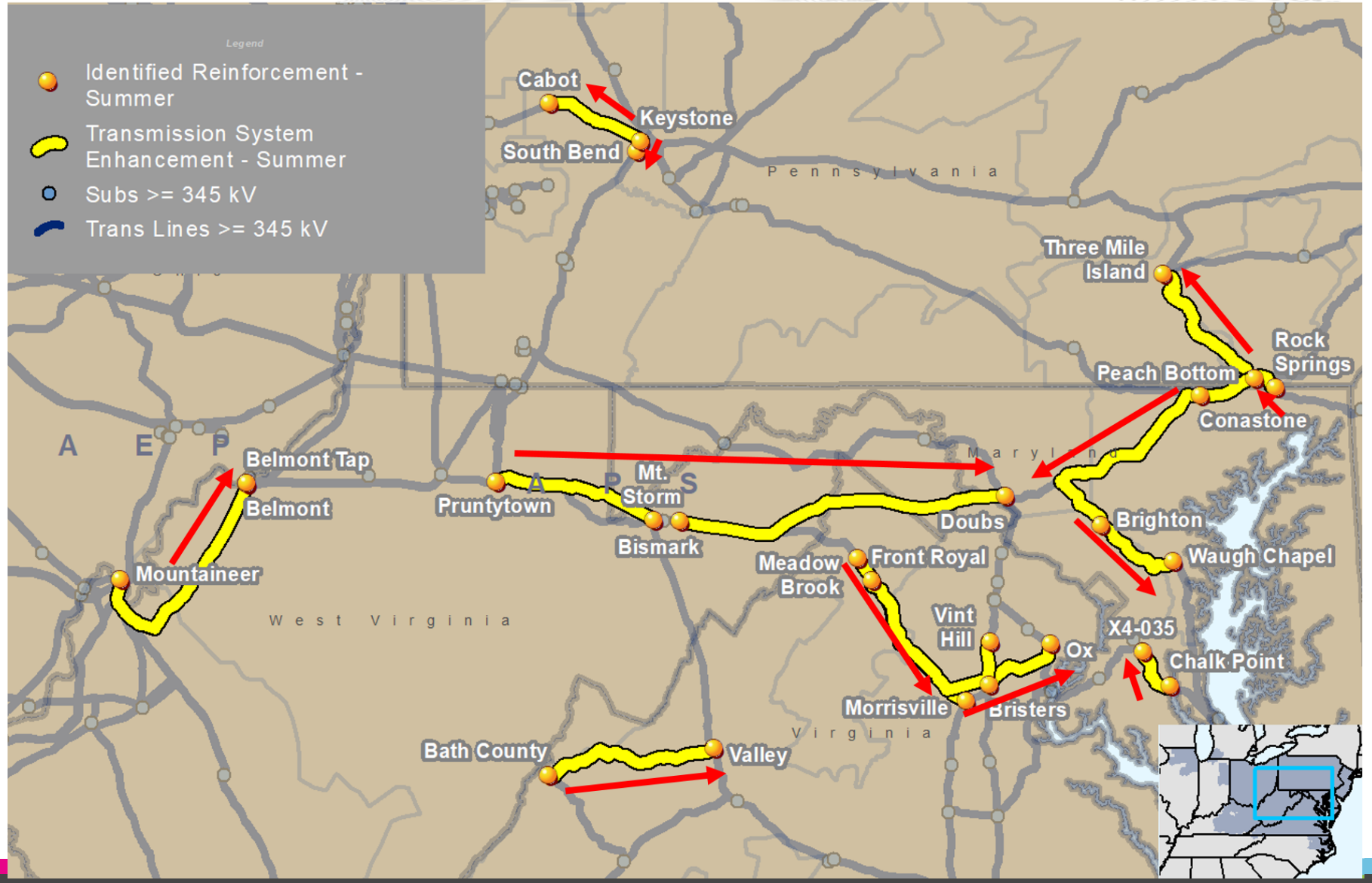
PJM©2023

High Level Summary



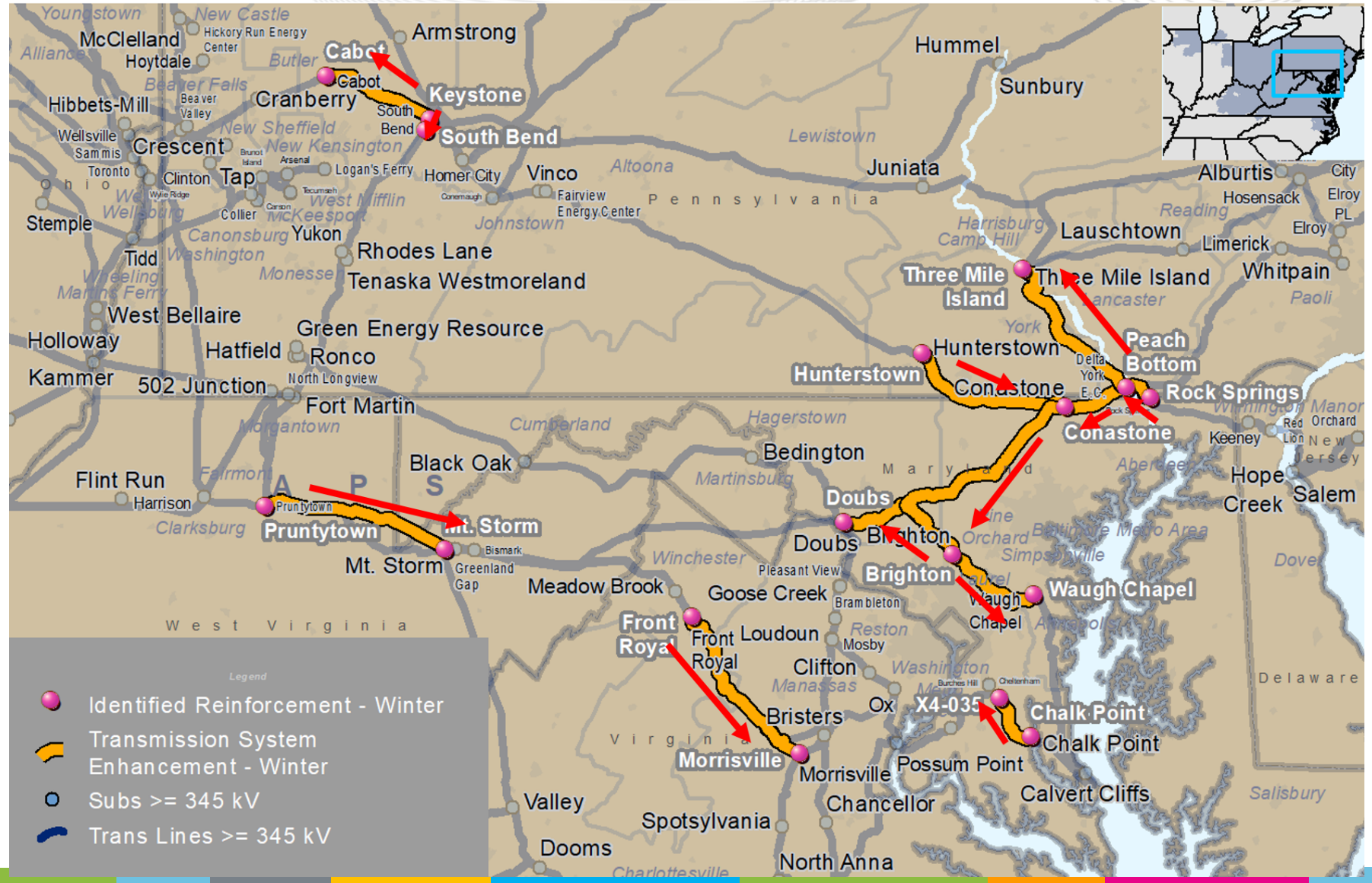
PJM©2023

Overloaded 500kV and above facilities in Summer Gen Deliv



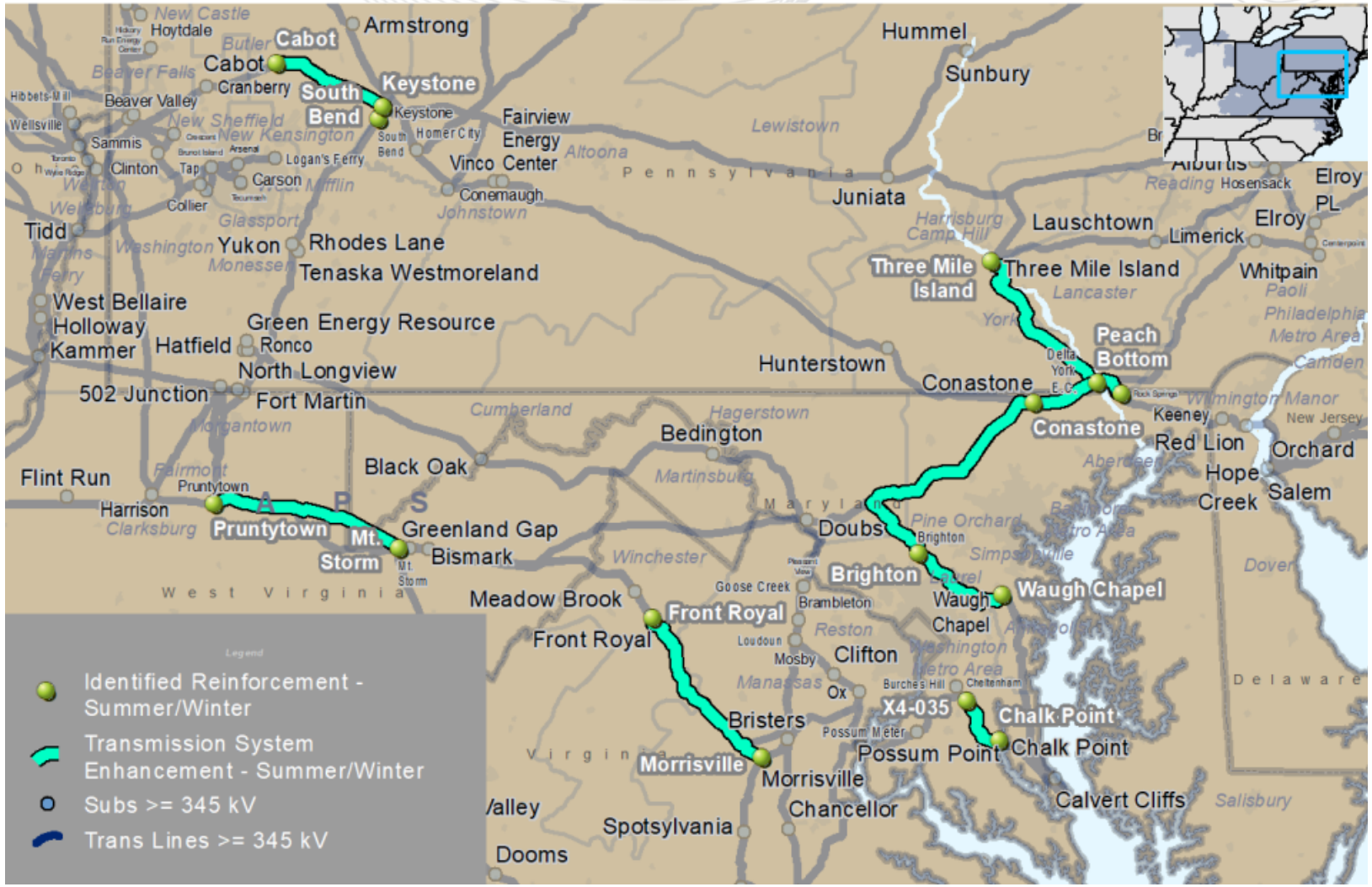
PJM©2023

Overloaded 500kV and above facilities in Winter Gen Deliv



PJM©2023

Overlap between Summer and Winter Violations



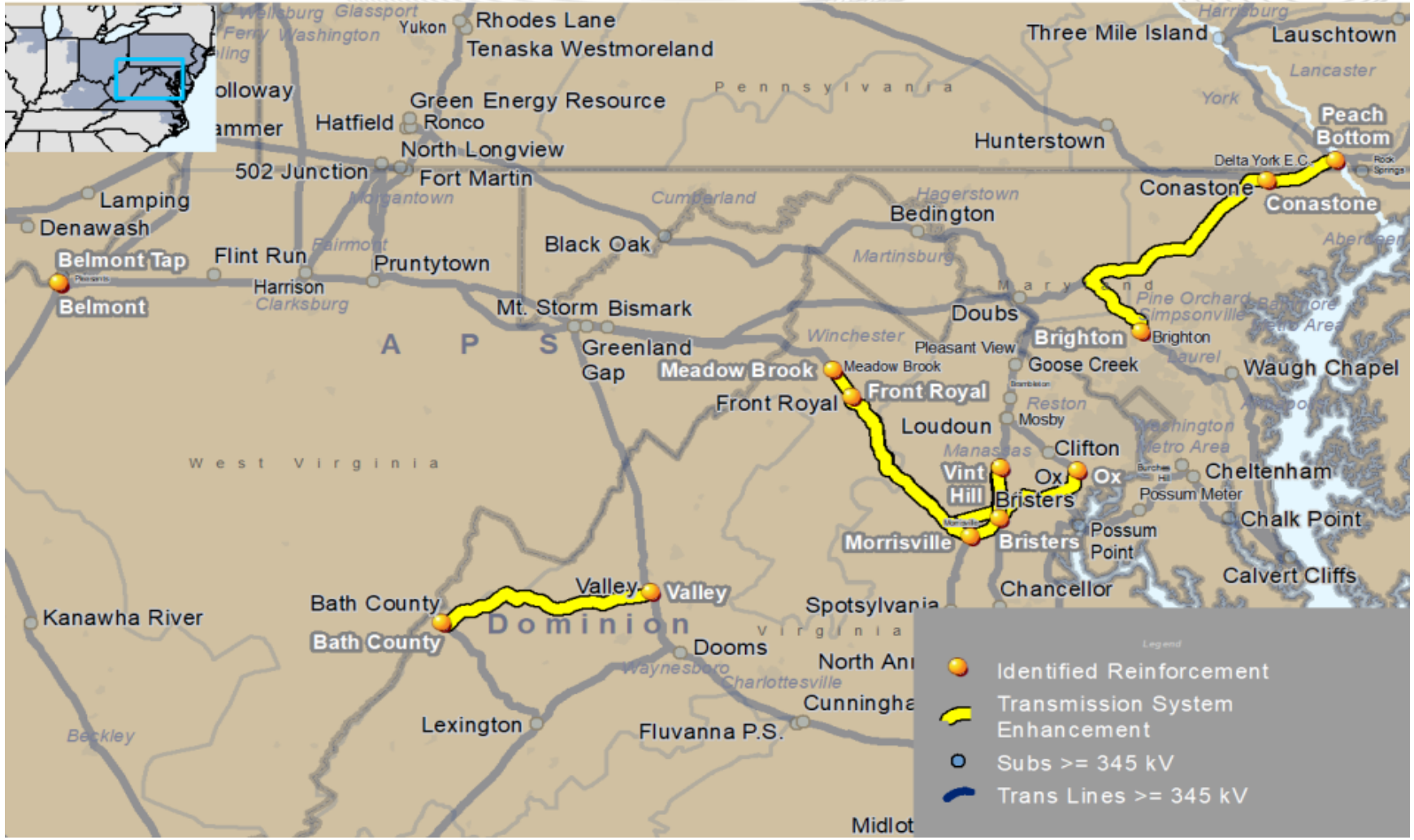
PJM©2023

Overloaded 500kV and above facilities

Fr Bus	Fr Name	To Bus	To Name	CKT	kVs	Summer	Winter
235110	01MDWBRK	313440	8VINTHIL	1	500	Y	N
235112	01PRNTY	314937	8MT STORM2	1	500	Y	Y
242920	05BELMON	235102	01BELMNT	5	765/500	Y	N
242516	05MOUNTN	242920	05BELMON	1	765	Y	N
314901	8BATH CO	314991	8VALLEY SC	1	500	Y	N
314941	8BISMARK	235105	01DOUBS	1	500	Y	N
314900	8BRISTER	314919	8OX	1	500	Y	N
314929	8FRONT ROYAL	314916	8MORRSVL	1	500	Y	Y
314916	8MORRSVL	313440	8VINTHIL	1	500	Y	N
314991	8VALLEY SC	314926	8VALLEY	1	500	Y	N
200003	BRIGHTON	200025	W CHAPEL	1	500	Y	Y
200018	CHALK PT	200301	X4-035 TAP	1	500	Y	Y
200004	CNASTONE	200003	BRIGHTON	1	500	Y	Y
200011	KEYSTONE	235118	01SOBEND	1	500	Y	Y
200011	KEYSTONE	235104	01CABOT	1	500	Y	Y
200066	PCHBTM1N	200016	3 MILE I	1	500	Y	Y
200066	PCHBTM1N	200065	PCHBTM2S	2	500	Y	Y
200064	PCHBTM1S	200004	CNASTONE	1	500	Y	Y
200065	PCHBTM2S	200064	PCHBTM1S	Z1	500	Y	Y
200065	PCHBTM2S	200064	PCHBTM1S	Z2	500	Y	Y
200065	PCHBTM2S	200066	PCHBTM1N	2	500	Y	Y
200051	ROCKSPGS	200065	PCHBTM2S	1	500	Y	Y
200003	BRIGHTON	235105	01DOUBS	1	500	N	Y
200026	HUNTERTN	200004	CNASTONE	1	500	N	Y

PJM©2023

500kV and above Facilities Limited by Conductor



PJM©2023

List of Facilities Limited by Conductor Summary

Fr Bus	Fr Name	To Bus	To Name	CKT	kVs	Areas	Pre Contingency Loading	Number of Single Contingencies and Worst Loading	Number of Breaker Contingencies and Worst Loading	Number of Tower Contingencies and Worst Loading	Number of Bus Contingencies and Worst Loading
235110	01MDWBRK	313440	8VINTHIL	1	500	201/345		(1)103%	(4)113%		
242920	05BELMON	235102	01BELMNT	5	765/500	201/205		(3) 110%	(3) 136%		
314901	8BATH CO	314991	8VALLEY SC	1	500	345		(1) 102%			
314900	8BRISTER	314919	8OX	1	500	345				(1) 104%	
314929	8FRONT ROYAL	314916	8MORRSVL	1	500	345		(1) 113%			
314916	8MORRSVL	313440	8VINTHIL	1	500	345		(7) 123%	(10) 131%	(3) 132%	
314991	8VALLEY SC	314926	8VALLEY	1	500	345		(1) 102%			
200004	CNASTONE	200003	BRIGHTON	1	500	225	185%	(13) 183%	(11) 188%	(12) 210%	(13) 179%
200064	PCHBTM1S	200004	CNASTONE	1	500	225	213%	(12) 188%	(15) 197%	(13) 195%	(12) 192%
200066	PCHBTM1N	200065	PCHBTM2S	2	500	225			(2) 141%		
200065	PCHBTM2S	200064	PCHBTM1S	Z1	500	225	100%	(2) 147%	(4) 215%		
200065	PCHBTM2S	200064	PCHBTM1S	Z2	500	225	114%	(9) 200%	(9) 211%	(4) 103%	(3) 105%

PJM©2023

Summary on the >= 500kV overloaded facilities

12 facilities are limited by conductor and expect to drive regional solutions

- **North:** Peach Bottom-Conastone –Brighton 500KV path is the most severe overload in the study (and overloaded in window 3). Peach Bottom 500kV station buses are heavily overloaded.
  - Loss of the Peach Bottom – Conastone 500kV line causes overloads on 22 different 230KV circuits
  - Loss of the Conastone – Brighton 500kV line causes overloads on 23 different 230kV circuits
  - Reinforcing the Peach Bottom-Conastone-Brighton path will relieve/avoid the associated 230 kV overloads in addition to addressing the existing 500kV path overload.
- **South:**
  - Morrisville – Vint Hill 500kV line and Bath County – Valley 500KV line are overloaded in Window 3,
  - The proposed solution for the above line could potential address/impact Meadow Brook – Vint Hill 500kV, Morrisville –Front Royal 500KV and Brister – OX 500KV overloads.
- **West:**
  - Belmont 765/500kV transformer

PJM©2023

Summary on the >= 500kV overloaded facilities -Continued

11 facilities are terminal equipment limited, can be addressed by substation equipment upgrades (subject to confirmation)

- **North:**
  - Peach Bottom – TMI 500KV line
  - Brighton – Doubs 500kV line
  - Chalk Point – X4-035 Tap 500kV line
  - Huntertown – Conastone 500kVline
  - Brighton – Waugh Chapel 500kVline
  - Rockspring – Peach Bottom 500KVline

- **West:**
  - Pruntytown –Mt. Storm 500kV line
  - Mountaineer - Belmont 765kV line
  - Bismark - Doubs 500KV line
  - Keystone – South Bend 500kV line
  - Keystone – Cabot 500kV line

PJM©2023

Key Takeaways

- Preliminary 2028 RTEP needs further affirm the earlier identified needs under 20227 RTEP W3 and the need for robust solutions.

- 2027 RTEP W3 solutions need to be robust
  - ➢ This allows for prudent right sizing of solutions
  - ➢ Solutions offered under 2027 W3 need to be “compatible” with the needs identified part of the 2028 RTEP.
  - ➢ Minimizes scope of the planned 2028 RTEP retool (towards end of 2023); enhances efficiency and timely development.

PJM©2023

Contact

Chair:
Sue Glatz, Suzanne.Glatz@pjm.com

Secretary:
Tarik Bensala, Tarik.Bensala@pjm.com

SMEs/Presenters:
Sami Abdulsalam, Sami.Abdulsalam@pjm.com

Wenzheng Qiu, Wenzheng.Qiu@pjm.com

Nebiat Tesfa, Nebiat.Tesfa@pjm.com



Member Hotline

(610) 666 – 8980

(866) 400 – 8980

custsvc@pjm.com

PJM©2023

Revision History

Version No.	Date	Description
1	4/26/2023	• Original slides posted

PJM©2023

PROTECT THE POWER GRID

THINK BEFORE YOU CLICK!

Be alert to malicious phishing emails.





Report suspicious email activity to PJM.

(610) 666-2244 / it_ops_ctr_shift@pjm.com

EXHIBIT NO. 55

Reliability Analysis Report

2022 RTEP Window 3

December 8, 2023 – R3

For Public Use

The information contained herein is based on information provided in project proposals submitted to PJM by third parties through its 2022 RTEP Window 3. PJM analyzed such information for the purpose of identifying potential solutions for the 2022 RTEP Window 3. Any decision made using this information should be based upon independent review and analysis and shall not form the basis of any claim against PJM.

This maps contained in this report are only intended to illustrate the general electrical connectivity of the projects and should not be relied upon for exact geographical substation locations or line routes.

CONTENTS

2022 RTEP Window 3 Reliability Analysis 4
Background 4
Case Development 5
2027 5
2028 6
Window Objective 7
Reliability Solutions and Initial Screening 8
Proposal Clusters/Groupings 8
Proposal Screening 11
Regional Proposal Components 16
Window 3 Evaluations Process 18
Consultation Meetings With Proposing Entities 18
Scenario Development 18
2027 Reliability Evaluation Summary 19
2027/28 Reliability Evaluation Summary 21
East Proposal Cluster 21
West Proposal Cluster 25
South Proposal Cluster 27
Northern Virginia Data Center Cluster 28
Short-Circuit Analysis 30
Load Deliverability Analysis 31
Selection of Short-Listed Scenarios and Proposal Components 32
NextEra Proposal 175 32
PJM Combination – 500 kV Scenario 32
PJM Combination – 765 kV Scenario 34
Final Reliability Analysis and Recommended Solution 35
AEP Local 36
South 37
Northern Virginia Data Center 45
East 48
West 53
Short Circuit 54
Critical Substation Planning Analysis 72
Power System Stability Analysis 72
Appendix A: Scope of Final Reliability Analysis 74
Criterion Applied by PJM for this Proposal Window 74

Appendix B: Window 3 Scenarios and Screening Performance 75
Document Revision History 163

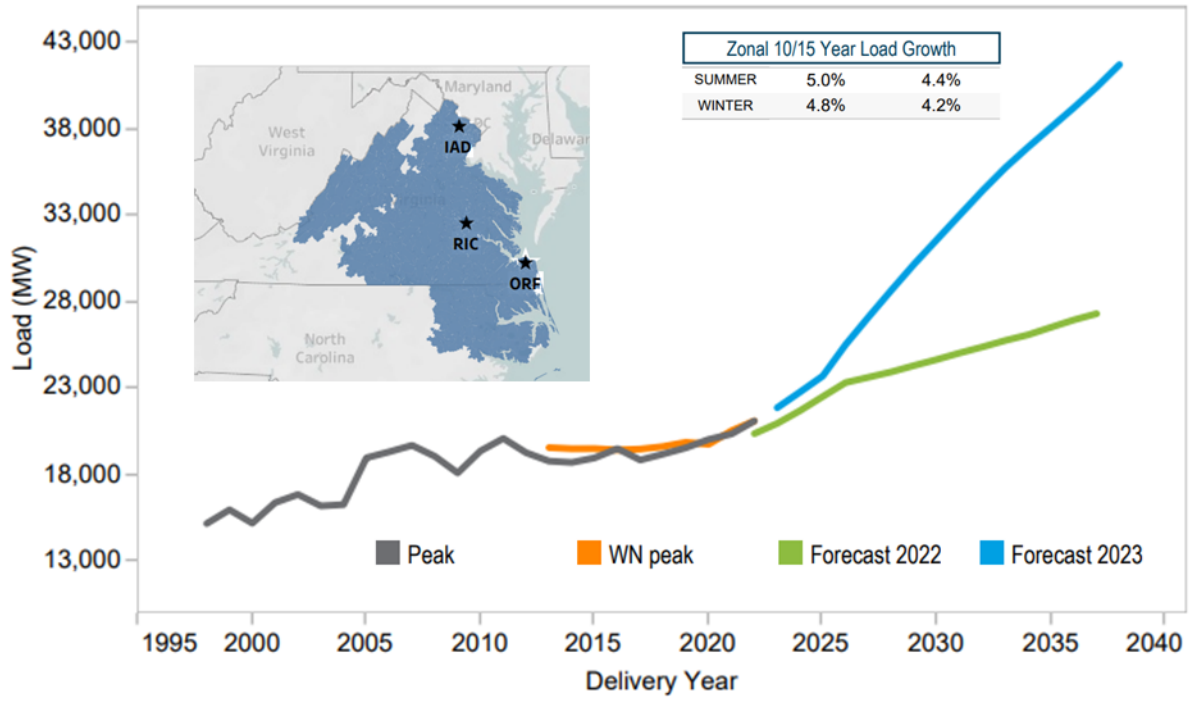
2022 RTEP Window 3 Reliability Analysis

Background

In early 2022, PJM shared its 2022 load forecast, which indicated high data center load growth activity, particularly in northern Virginia. In July 2022, PJM directed an immediate need transmission enhancement project to enable the integration of the forecasted data center load up to and including year 2025. Since then, data center loads within northern Virginia have been increasing at an unprecedented rate, and new data center load is being proposed in Maryland near the Doubs substation. As shown in **Table 1**, the recorded actual summer peak in 2022 was 21,156 MW while the 2022 forecast called for 20,424 MW. In an effort to stay ahead of these rapid increases, PJM continued its consultation efforts with Transmission and Distribution Owners in the area to refine its forecast and further enhance its need assessment.

PJM began receiving near and long term forecast input from Dominion, First Energy and NOVEC for data center load growth projections up to and including 2038 (15-year planning horizon). The PJM 2023 forecast calls for between 4.2% and 5.0% annual load growth in the Dominion area over the next 10- to 15-year time frame as shown in **Figure 1** below. The Load Forecast information was refined and modeled at a bus/substation level for the 2028 and 2030 study years, and PJM reassessed the transmission development needs in the area based on the refined forecast information and localized allocation of load.

Figure 1. Dominion 2023 Summer Peak Load Forecast



The data center load growth rate (currently concentrating in areas of northern Virginia) continues to increase. FirstEnergy's APS zone (just north of Virginia) is also experiencing data center load development, driving high flows within the northern Virginia transmission system, into the data center concentrated load pocket. The 2027 and 2027/28 study cases summer zonal load for Dominion and First Energy is provided in **Table 1**.

There are regional flows from the following:

- West and East toward Doubs-Goose Creek
- South into and out of Bristers toward Loudon

Major voltage support needs within Dominion and APS will be required. Some of the voltage violations are observed under N-0 conditions (fictitious MVARs were modeled in order to solve the case), and heavy regional transfers will require additional reinforcements to support the regional transfers.

Table 1. 2027/28 Case Summer Zonal Load for Dominion and FirstEnergy

	Summer Zonal Load (MW)	
Study Case	**Dominion/NOVEC**	**FirstEnergy (APS)**
2022 Peak	20,424 (forecast)/21,156 (actual)	8,675 (forecast)/8,412 (actual)
2027 RTEP	23,681	8,780
2027 Baseline	26,393	9,607
2027 High Load Growth	28,893	10,559
2028 RTEP (2023 Load Forecast)	28,705	9,568
Data Center Component Load (modeled in cases)	~5,700	~1,500

Case Development

2027

The 2022 RTEP Window 3 cases are based upon the 2022 RTEP, five-year out 2027 case with the following included:

- 2027 Dominion immediate need solution b3718
- 33 Dominion supplemental projects presented through the M-3 process from January to September of 2022
- Bus level data center load additions
- Summer, winter and light load cases were developed for baseline and high load growth scenarios

The immediate need baseline project, b3718, builds a new 500/230 kV substation called Wishing Star near Brambleton substation and installs one 500/230 kV 1440 MVA transformer at the substation. A new 500/230 kV substation called Mars will be built near Dulles International Airport, and one 500/230 kV 1440 MVA transformer will be installed at the substation. The 500 kV line No. 546 (Brambleton-Mosby) and 500 kV line No. 590 (Brambleton-Mosby) will be cut and extended to the proposed Wishing Star substation, and lines will terminate in a 500 kV breaker and a half configuration.

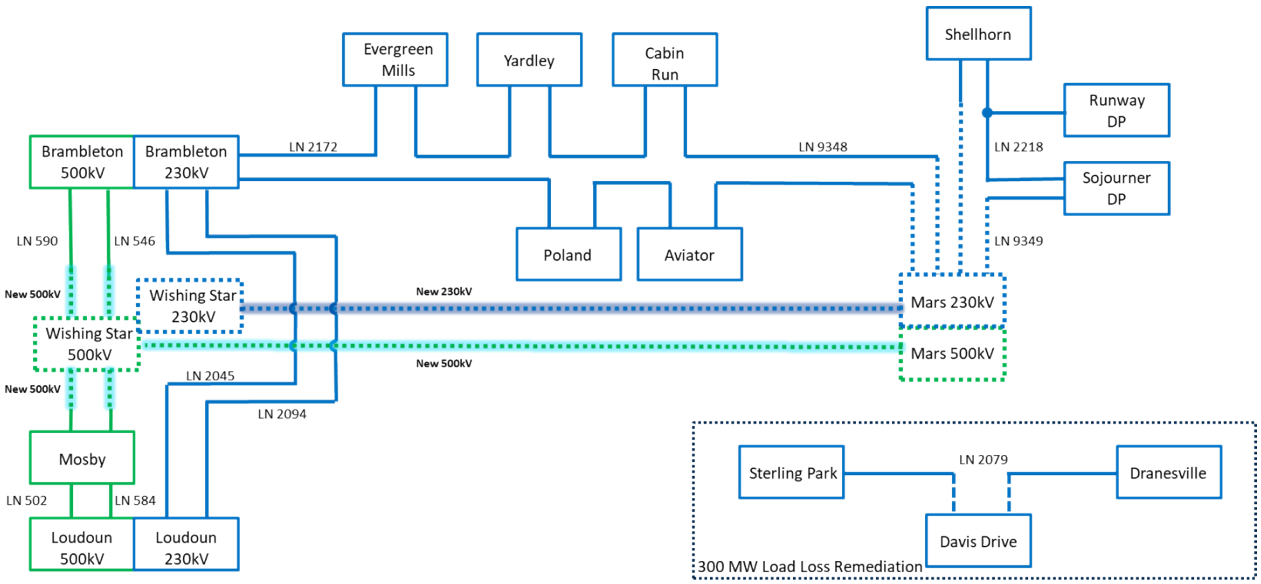
The project will reconductor the approximate mileage of the following lines:

- 0.62 miles of 230 kV line No. 2214 (Buttermilk-Roundtable)
- 1.52 miles of 230 kV line No. 2031 (Enterprise-Greenway-Roundtable)

- 0.64 miles of 230 kV line No. 2186 (Enterprise-Shellhorn)
- 2.17 miles of 230 kV line No. 2188 (Lockridge-Greenway-Shellhorn)
- 0.84 miles of 230 kV line No. 2223 (Lockridge-Roundtable)
- 3.98 miles of 230 kV line No. 2218 (Sojourner-Runway-Shellhorn)
- 1.61 miles of 230 kV line No. 9349 (Sojourner-Mars)

The project will also upgrade four 500 kV breakers to 63 kA on either end of 500 kV line No. 584 (Loudoun-Mosby circuit No. 1) and four 500 kV breakers to 63 kA on either end of 500 kV line No. 502 (Loudoun-Mosby circuit No. 2), cut and loop the 230 kV line No. 2079 (Sterling Park-Dranesville) into the Davis Drive substation and install two GIS 230 kV breakers. **Figure 2** below shows a high-level illustration of the project scope. The PJM Board approved cost for this project is $627.62 million. This project is identified as immediate need, with a required in-service date of June 2025. The projected in-service date for all project components is December 2026. The local transmission owner, Dominion, was designated to complete this work.

Figure 2. Dominion Immediate Need Solution b3718



2028

In addition to the data center load growth currently forecasted by 2027/2028 in Dominion (northern Virginia) and APS (Doubs) zones, there are a number of additional drivers necessitating the need for transmission development. Over the past two years, there has been approximately 11,100 MW of announced generator deactivations to the west and south of Conastone, about 5,300 MW of which occurred after the Window 3 2027 case was created. The replacement generation is coming from the region to the east of Peach Bottom as well as west of Doubs to meet projected load growth.

PJM has also implemented a new block dispatch procedure in the 2023 RTEP that more accurately reflects real-time operations dispatch and no longer tries to maintain historical intraregional transfer levels. The old dispatch procedure would have dispatched most of the generators in the Dominion zone at 100% or higher to maintain historical regional interchange. The 2028 case is subject to new generator deliverability testing requirements. After observing initial

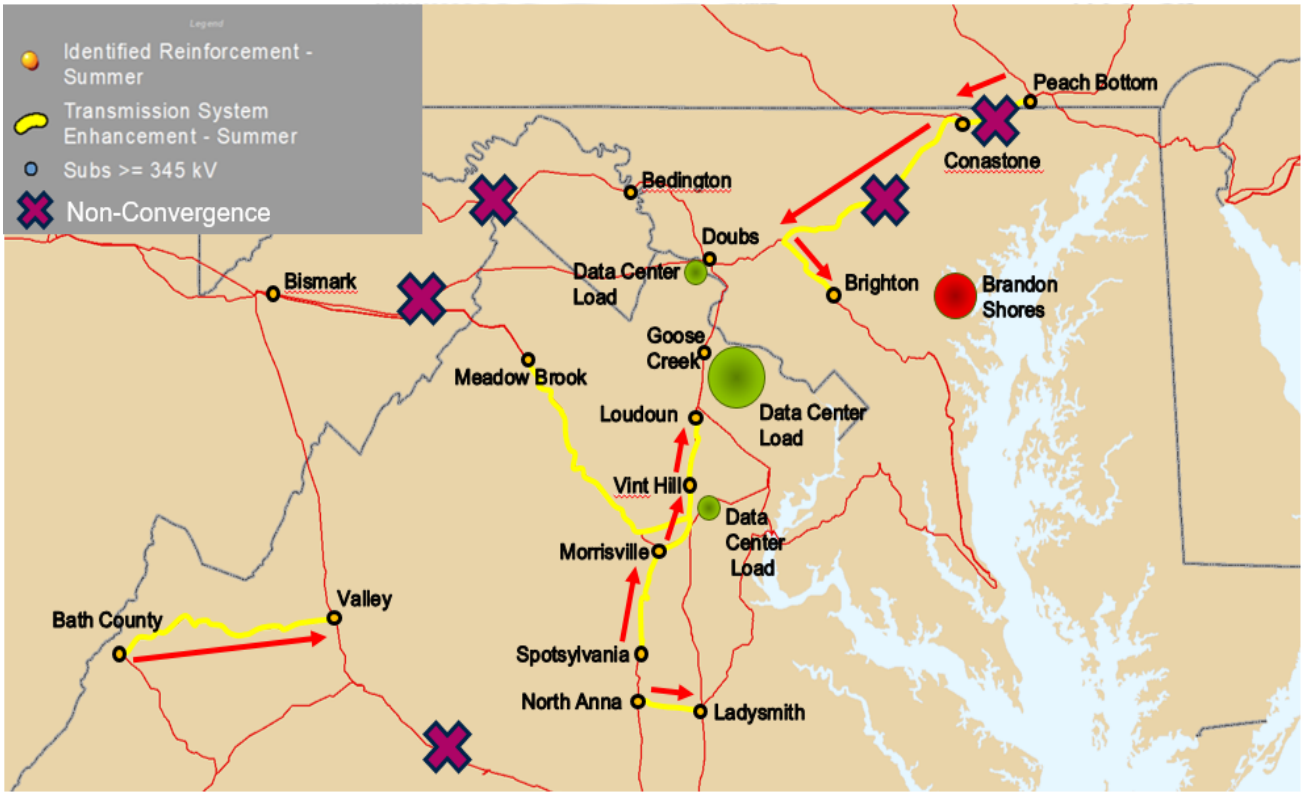
2028 analysis results, which showed an increased number and severity of overloads, PJM determined it would be prudent to utilize the 2028 cases to evaluate the proposals for robustness.

Window Objective

The objective of the 2022 RTEP Window 3 is to develop robust, holistic and expandable solutions that address the 2027/28 baseline violations as illustrated in **Map 1** associated with:

- **Local Constraints:** Resulting from directly serving the data center loads in APS and Dominion zones through the respective 230 kV networks and into the points of delivery:
  - Goose Creek-Ashburn-Mars-Wishing Star and Brambleton
- **Regional Constraints:** Resulting from imports into load center areas (500 kV primarily):
  - Doubs-Goose Creek
  - Front Royal-Morrisville-Vint Hill-Loudoun/Mosby
  - Meadow Brook-Loudoun/Mosby
  - Morrisville-Bristers-Ox
  - Peach Bottom-Conastone-Brighton-Doubs
- **Reactive Power Needs:** Needed reactive power MVAR reinforcements, both static and dynamic as deemed necessary, to address the reactive power needs of the system for the 2027/28 baseline scenario
- **Cummulative Impact of Generation Changes and Deactivations**:
  - 11,100 MW of announced deactivations to the west and south of Conastone
  - Approximately 5,300 MW occurring after the 2022 RTEP 2027 case was created
  - The vast majority of the new generation with signed ISAs has been solar, which has low availability during the winter period.
  - The replacement generation is coming from the region to the east of Peach Bottom as well as west of Doubs to meet projected load growth.
  - PJM has implemented a new block dispatch procedure.
  - The old dispatch procedure in the past (including that implemented in the 2027 study cases) maintained historical intraregional transfers, dispatching most of the generators in the Dominion zone at 100%.
- **Adherance to All Applicable Criteria:** The recommended solution must adhere to all applicable planning criteria, including PJM, NERC, SERC, RFC and local Transmission Owner FERC 715 criteria.

Map 1. 2022 RTEP Window 3 Map of Regional/Local Needs



Reliability Solutions and Initial Screening

PJM received 72 proposals from ten different entities as part of this window (**Table 2**). Of the ten proposing entities, six were incumbent Transmission Owners (TOs) and four were non-incumbent entities. PJM received 22 proposals that are upgrades, and received 50 greenfield proposals. The total cost of all proposals, not all of which are required, add up to approximately $54.4 billion. The proposals include:

- 230 kV, 500 kV and 765 kV developments
- HVDC developments
- Underground 500 kV AC cable developments
- 500 kV GIS substations
- Double circuit 500 kV proposals

Proposal Clusters/Groupings

The below **Map 2** shows the regional nature of the proposals, concentrating in four clusters: West, South, East, and Northern Virginia data center areas. Each cluster included proposals by different entities in the same need area and/or addressed the same local/regional needs.

Map 2. Regional Clusters

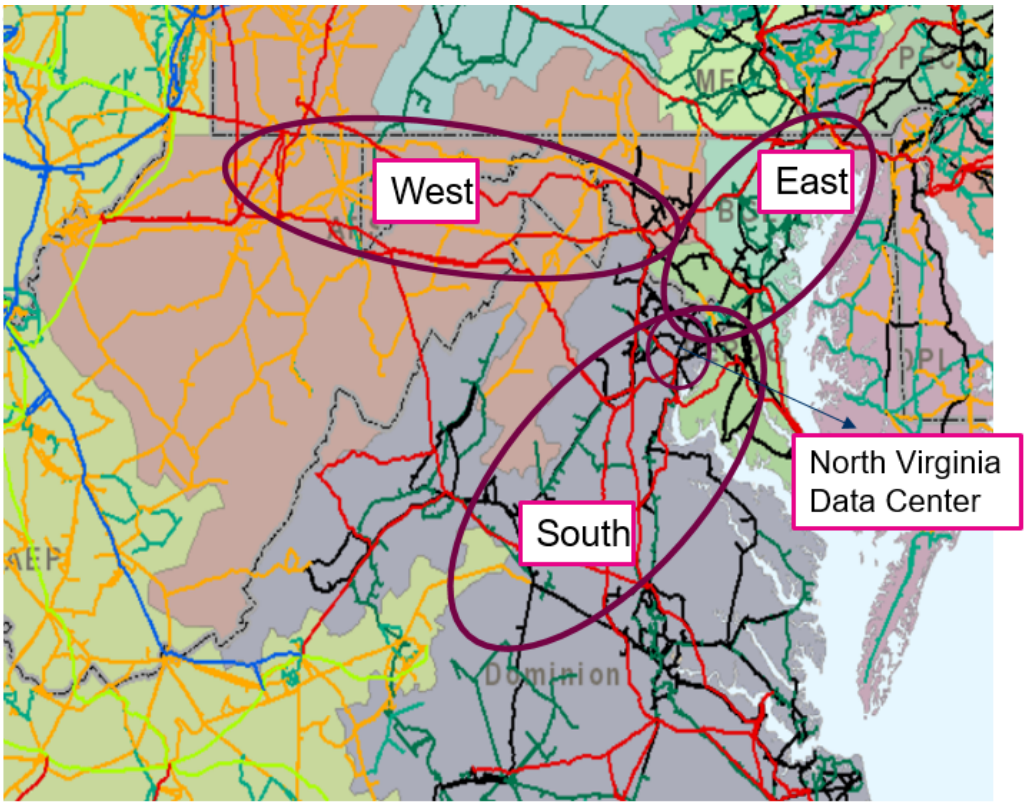


Table 2. 2022 RTEP Window 3 Submitted Proposals

#	ID	Proposing Entity	Focus Area	Project Title	Submitted Cost ($M)
1	9	AEP	Local AEP	Scottsville-Bremo Sag Study	$1.27
2	55			Boxwood-Scottsville 138 kV Rebuild	$104.88
3	181			Boxwood-Scottsville 138 kV Sag Study	$4.26
4	196			Glen Lyn-Peters Mountain Rebuild	$21.89
5	202			Cloverdale Transformer Addition	$57.29
6	234			Glen Lyn-Peters Mountain Sag Study	$0.80
7	410			Cloverdale Breaker Reconfiguration	$11.59
8	477			Fieldale-Franklin Rebuild	$74.89
9	524			Opossum Creek and New London Reactors	$8.86
10	537			Fieldale-Franklin Sag Study	$30.19
11	629			Scottsville-Bremo Rebuild	$31.31
12	856			Leesville-Altavista Rebuild	$28.85
13	487	AEP - Transource	Combo	Maryland & Pennsylvania Baseline Reliability Solution	$492.75
14	858		South	Stork-Flys 500 kV Greenfield Line and Substations	$510.44
15	904		Combo	Joshua Falls-Yeat 765 kV Greenfield Line and Substation	$1,048.10
16	977		South	Yeat 500/230 kV Greenfield Station	$232.14
17	30	Dominion	Local DOM	Charlottesville-Hollymead Line No. 2054 Rebuild	$159.87

#	ID	Proposing Entity	Focus Area	Project Title	Submitted Cost ($M)
18	74	Dominion	Local DOM	Line No. 2090 (Ladysmith CT-Fredericksburg) Rebuild	$57.34
19	129		South	Dominion Aggregate 500 kV Proposal	$3,035.05
20	211		Local DOM	Hollymead-Gordonsville Line No. 2135 Rebuild	$54.85
21	231			Reactive Power VAR Reinforcements	$155.82
22	516		East	Interregional solution- Aspen-Doubs Second 500 kV Line	$61.72
23	671		South	Line No. 541 (Front Royal to Morrisville) Rebuild	$299.03
24	692		South	Data Center Alley Local solution-New 500 kV/230 kV Aspen-Golden & Golden-Mars lines	$1,058.45
25	704		Local DOM	Hollymead-Gordonsville Line No. 2135 Rebuild	$36.89
26	711		South	Regional Solution-500 kV North Anna-Wishing Star Upgrades	$1,227.84
27	731		Local DOM	Locks Substation 230/115 kV Transformer Upgrade	$7.14
28	923		South	Second 500 kV line from Lexington to Dooms	$232.18
29	967		Local DOM	Charlottesville-Hollymead Line No. 2054 Rebuild	$183.48
30	548	LSPower	Scenario	RTEP Window 3 Solution	$2,404.48
31	28	NextEra	East/West	Hunterstown-Doubs-Goose Creek, Black Oak-Pike-Goose Creek, Pike SVC + Cap Banks	$884.05
32	116			Hunterstown-Doubs-Gant Solution	$478.87
33	175		Scenario	Combination of PEBO 215A + WOP 1F + SOP 8E	$6,265.95*
34	217		East	North Delta-Conastone Solution	$155.99
35	255		West	Hunterstown-Doubs-Gant Solution	$411.61
36	279			Black Oak-Woodside-Goose Creek, Woodside SVC + Cap Banks Solution	$429.18
37	347			Black Oak-Woodside-Gant, Woodside SVC + Cap Banks	$483.83
38	385		East	New 500/230 kV Bartholow substation, new 500/230 kV North Delta substation, new 230 kV Grisham switchyard, new 500/230 kV Goram substation	$1,140.73
39	419		East/West	Hunterstown-Doubs-Audobon-Goose Creek	$548.75
40	445		East	Muddy Creek/Delta-Conastone/Hunterstown-Doubs-Goose Creek Solution	$637.80
41	530			Muddy Creek/North Delta-Conastone Solution	$166.74
42	564			New 500/230 kV Bartholow substation, new 500/230 kV North Delta substation, new 230 kV Grisham switchyard, new 500/230 kV Goram substation	$876.88
43	577		South	Front Royal-Racefield, Warrenton-Wheeler, North Anna-Lady Smith	$258.38
44	598		Scenario	Combination of PEBO 220 + WOP 1F + SOP 8E	$2,036.47
45	631		East	Muddy Creek/North Delta-Conastone Solution	$184.47
46	642		West	502 Junction-Black Oak-Woodside-Gant, Woodside SVC + Cap Banks, Gant-Farmwell, Cochran Tap-Round Table	$747.31
47	663		South	Front Royal-Racefield, Warrenton-Rixlew, Warrenton-Hourglass, Mars-Ocean Court-Davis Drive	$284.17
48	676	NextEra	West	Black Oak-Stonewall-Gant, Stonewall SVC + Cap Banks, Gant-Farmwell, Cochran Tap-Round Table Solution	$552.49
49	685			Ft. Martin-Black Oak-Woodside, Woodside SVC + Cap Banks Solution	$609.78
50	719			Ft. Martin-Black Oak-Pike, Pike SVC + Cap Banks Solution	$600.90

#	ID	Proposing Entity	Focus Area	Project Title	Submitted Cost ($M)
51	728			Barnhart Substation, Bartholow Substation, Barnhart-Bartholow-Goose Creek solution	$385.36
52	766		South	Front Royal-Racefield, Warrenton-Wheeler	$239.59
53	846		West	Hunterstown-Doubs-Goose Creek, Black Oak-Woodside-Goose Creek, Stonewall SVC + Cap Banks	$892.94
54	853			502 Junction-Black Oak-Woodside-Gant, Woodside SVC + Cap Banks	$683.55
55	948		East	New 500/230 kV Bartholow substation, new 500/230 kV North Delta substation, new 230 kV Grisham switchyard, new 500/230 kV Goram substation, and Keeney to Waugh Chapel tie-in.	$5,381.25*
56	951		West	Black Oak-Gore-Goose Creek, Pike SVC + Cap Bank Solution	$419.86
57	344	PECO	East	PECO Expansion Plan for DOM Window 2023	$302.86
58	600		Local Other	Exelon Replacement Upgrades	$423.79
59	660	PEPCO	East	West Cooper BGE-PEPCO	$1,105.62
60	691			Mid-Atlantic Power Pathway (MAPP)	$1,990.28
61	23	POTOED - FirstEnergy	Combo	Data Center Reinforcement Proposal No. 2	$3,503.86
62	837			Data Center Reinforcement Proposal No. 1	$2,991.77
63	374	PPL	East	Otter Creek-Conastone 500 and 230 kV DCT Line	$154.21
64	606		Local Other	Juniata-Lewistown 230 kV No. 2 line	$141.16
65	24	PSEG	East	Proposal A-North Delta-New Raphael-Waugh Chapel 500 kV	$739.40
66	125		Local Other	Proposal B-North Delta-Northeast 230 kV	$313.34
67	229		East	Proposal C-Hunterstown-New Green Valley 500 kV	$529.11
68	325		Combo	Proposal E-Brambleton-Hinsons Ford Rd 500 kV	$944.05
69	637		East	Proposal D-Conastone-Doubs 500 kV	$684.22
70	741			Proposal G-Peach Bottom-New Brandon Shores 500 kV; Peach Bottom-Doubs 500 kV	$1,065.32
71	808			Proposal F-Peach Bottom-New Raphael-Waugh Chapel 500 kV; Peach Bottom-Doubs 500 kV	$1,150.80
72	962			Proposal H-Peach Bottom-Doubs 500 kV (Circuits No. 1 and No. 2)	$977.71
				Total:	**$54,408.06**

**The proposal cost was increase due to cost revision provided by proposing entity from approximately $1.6 billion to $5.4 billion.*

Proposal Screening

PJM performed a generator deliverability screening of all proposals on the 2027 cases to obtain a preliminary understanding of performance. It is important to note that many of the proposals are not intended to be standalone projects, as they are intended to be combined with other proposals in order to address flowgate violations. **Table 3** and **Table 4** summarize the performance evaluation results of all 72 submitted proposals. The tables summarize the intended flowgates by each proposal as specified in the proposing entity submission, the remediated flowgates as confirmed by PJM testing, the total addressed/unaddressed flowgates out of all window flowgates and whether the proposal, on its own, introduces any new flowgates. Where a high number of unaddressed flowgates are shown in the

Table 3, such as for some of Dominion and NextEra proposals, the specific proposals are either combined with other entitys' proposals and/or part of a larger scenario proposal.

Table 3. 2027 Proposal Summary by Number of Flowgates (FG)

#	ID	Proposing Entity	Focus Area	Project Intended FG	Remediated FG Intended	Unaddressed FG Intended	Addressed FG Posted (out of 527)	Unaddressed FG Posted (out of 527)	New FG Attributed to Project
1	9	AEP	Local AEP	0	0	0	36	491	13
2	55			16	16	0	61	466	17
3	181			16	14	2	55	472	6
4	196			1	1	0	44	483	17
5	202			1	1	0	43	484	11
6	234			1	1	0	43	484	10
7	410			1	1	0	180	347	79
8	477			2	2	0	176	351	81
9	524			2	2	0	176	351	82
10	537			2	2	0	169	358	20
11	629			0	0	0	175	352	83
12	856			2	1	1	175	352	87
13	30	Dominion	Local DOM	3	3	0	47	480	22
14	74[1]			108	4	104	44	483	7
15	129[1]		South	117	84	33	149	378	46
16	211[1]		Local DOM	113	7	106	52	475	11
17	231[1]			108	11	97	58	469	16
18	516		PB-C	15	15	0	195	332	25
19	671		Local DOM	0	0	0	43	484	8
20	692		South	62	62	0	127	400	11
21	704		Local DOM	2	2	0	49	478	7
22	711		South	35	33	2	127	400	143
23	731[1]		Local DOM	108	4	104	47	480	7
24	923		South	3	3	0	49	478	11
25	967[1]		Local DOM	114	7	107	47	480	22
26	600	Exelon	Local Other	126	124	2	287	240	81
27/28	660/344		PB-C	96	96	0	309	218	91
29	23[1]	FE (POTOMAC)	Combo	501	419	82	433	94	35
30	837[1]			501	421	80	434	93	21
31	548	LS Power	Scenario	515	509	6	518	9	32
32	28[1]	NextEra	West	339	263	76	306	221	102
33	116[1]			294	246	48	275	252	66
34	217[1]		PB-C	170	139	31	244	283	82
35	255[1]		West	298	189	109	249	278	86

[1] These proposals are designed to work in tandem with other proposal components submitted by the same proposing entity. The performance of these proposals is further judged through the scenario analysis exercise instead of individually only

#	ID	Proposing Entity	Focus Area	Project Intended FG	Remediated FG Intended	Unaddressed FG Intended	Addressed FG Posted (out of 527)	Unaddressed FG Posted (out of 527)	New FG Attributed to Project
36	279[1]			260	170	90	239	288	102
37	347[1]			228	165	63	237	290	105
38	385		PB-C	378	372	6	500	27	313
39	419[1]		West	492	242	250	272	255	81
40	445[1]		PB-C	318	268	50	306	221	105
41	530			1	1	0	236	291	86
42	564[1]			375	333	42	355	172	38
43	577[1]		South	127	75	52	163	364	208
44	598		Scenario	634	630	4	510	17	10
45	631[1]		PB-C	181	150	31	248	279	93
46	642[1]		West	353	257	96	303	224	176
47	663[1]		South	170	100	70	166	361	211
48	676[1]		West	253	189	64	277	250	93
49	685[1]			299	210	89	265	262	227
50	719[1]			297	197	100	252	275	231
51	728[1]			494	189	305	206	321	153
52	766[1]		South	127	74	53	160	367	208
53	846[1]		West	344	270	74	314	213	102
54	853[1]			301	210	91	266	261	99
55	948[1]		PB-C	382	341	41	365	162	31
56	951[1]		West	220	162	58	231	296	111
57	175		Scenario	466	463	3	510	17	11
58	374	PPL	PB-C	8	8	0	142	385	27
59	606[1]		Local Other	14	10	4	46	481	17
60	24	PSEG	PB-C	158	148	10	286	241	76
61	125		Local Other	111	110	1	268	259	71
62	229[1]		PB-C	191	177	14	295	232	93
63	325[1]		Combo	192	168	24	304	223	81
64	637		PB-C	161	148	13	281	246	101
65	741			194	184	10	290	237	88
66	808			198	188	10	327	200	79
67	962			181	164	17	283	244	97
68	487	TRANSRC	Combo	317	307	10	438	89	5
69	858		South	63	61	2	169	358	18
70	904		Combo	148	142	6	295	232	39
71	977		South	26	26	0	196	331	26

NOTE: Proposal 691 case did not converge, so no results are shown.

[1] These proposals are designed to work in tandem with other proposal components submitted by the same proposing entity. The performance of these proposals is further judged through the scenario analysis exercise instead of individually only

Table 4. 2027 Proposal Summary by Number of Facilities

#	ID	Proposing Entity	Focus Area	No Longer Overloaded (out of 146)	Remaining Overloads (out of 146)	New Overloads
1	9	AEP	Local AEP	15	131	1
2	55			20	126	1
3	181			19	127	0
4	196			16	130	0
5	202			16	130	0
6	234			16	130	0
7	410			45	101	10
8	477			45	101	9
9	524			44	102	10
10	537			48	98	0
11	629			44	102	11
12	856			42	104	10
13	30	Dominion	Local DOM	19	127	0
14	74			17	129	0
15	129		South	43	103	6
16	211		Local DOM	17	129	0
17	231			15	131	1
18	516		PB-C	65	81	3
19	671		Local DOM	18	128	0
20	692		South	37	109	2
21	704		Local DOM	17	129	0
22	711		South	39	107	7
23	731		Local DOM	16	130	0
24	923		South	18	128	0
25	967		Local DOM	19	127	0
26	600	Exelon	Local Other	63	83	11
27/28	660/344		PB-C	60	86	22
29	23	FE (POTOMAC)	Combo	97	49	6
30	837			100	46	3
31	548	LS Power	Scenario	114	32	11
32	28	NextEra	West	52	94	16
33	116			50	96	13
34	175		Scenario	117	29	4
35	217		PB-C	54	92	10
36	255		West	44	102	16
37	279			41	105	7
38	347			41	105	7
39	385		PB-C	81	65	13

#	ID	Proposing Entity	Focus Area	No Longer Overloaded (out of 146)	Remaining Overloads (out of 146)	New Overloads
40	419		West	55	91	18
41	445		PB-C	58	88	21
42	530			53	93	12
43	564			81	65	13
44	577		South	32	114	25
45	598		Scenario	117	29	3
46	631		PB-C	54	92	16
47	642		West	64	82	17
48	663		South	38	108	26
49	676		West	56	90	5
50	685			45	101	25
51	719			43	103	21
52	728			40	106	23
53	766		South	33	113	26
54	846		West	49	97	16
55	853			49	97	9
56	948		PB-C	80	66	10
57	951		West	36	110	7
58	374	PPL	PB-C	32	114	1
59	606		Local Other	16	130	1
60	24	PSEG	PB-C	53	93	16
61	125		Local Other	59	87	12
62	229		PB-C	58	88	22
63	325		Combo	52	94	19
64	637		PB-C	51	95	18
65	741			58	88	18
66	808			70	76	16
67	962	PSEG	PB-C	56	90	19
68	487	TRANSRC	Combo	100	46	0
69	858		South	56	90	0
70	904		Combo	69	77	2
71	977		South	49	97	1

NOTE: Proposal 691 case did not converge, so no results are shown.

The proposals submitted by AEP were intended to address local AEP flowgates posted with the window and were not included in the cluster evaluations. The proposals were evaluated in the 2027 and 2028 cases and addressed the posted flowgate violations.

Regional Proposal Components

The first step to scenario development was to cluster the 500 kV and above proposal components to determine the more efficient or cost-effective combination of backbone solution components. **Table 5** through **Table 8** organize the backbone proposal components into regional clusters.

Table 5. East Cluster

Proposal ID	Proposing Entity	List Components
344/660-1	Exelon	Peach Bottom North-Graceton New 500 kV West Cooper-Peach Bottom South New 500 kV Line West Cooper-High Ridge 500 kV Rebuild 5012 500 kV (will be looped in to West Cooper and Gracetone)
344/660-2		West Cooper-Peach Bottom South New 500 kV Line West Cooper-High Ridge 500 kV Rebuild 5012 500 kV (will be looped in to West Cooper)
344/660-3		Peach Bottom North-Graceton New 500 kV West Cooper-Peach Bottom South New 500 kV Line Rebuild 5012 500 kV (will be looped in to West Cooper and Gracetone)
691		230 mile, 500 kV AC/400 kV DC (Possum Pt-Burches Hill-Cheltenham-Chalk Pt. Mission to Salem 500 kV) Hallowing (HVDC)-Mission (HVDC)
548	LS Power	Conastone-North Delta 500 kV
		Huntersdown-Doubs 500 kV
217	NextEra	North Delta-Conastone 500 kV
385/564		New Otter Creek-Bartholow (Conastone-Brighton tap, Doubs-Brighton Tap) 500 kV
385/564		North Delta-Conastone 500 kV
530		North Delta-Conastone 500 kV
948	NextEra	New Otter Creek-Bartholow (Conastone-Brighton tap, Doubs-Brighton Tap) 500 kV
948		North Delta-Conastone 500 kV
374	PPL	Otter Creek-Conastone 500 and 230 kV DCT Line
229	PSEG	Hunterstown-Green Valley 500 kV
24		N. Delta-New Raphael-W. Chapel 500 kV
325		N. Delta-New Raphael-W. Chapel 500 kV
637		Conastone-Doubs 500 kV
741		Peach Bottom-Brandon Shore 500 kV
741		Peach Bottom-Doubs 500 kV
808		Peach Bottom-Raphael-W. Chapel 500 kV
808		Peach Bottom-Doubs 500 kV
962		Peach Bottom-Doubs 500 kV (two lines)

Table 6. West Cluster

Proposal ID	Proposing Entity	List Components
23	FE	Fort Martin-Doubs 500 No. 1 & 2
23		Meadow Brook-Doubs 500 kV
23		Meadow Brook-Pruntytown 500 kV
837		Fort Martin-Doubs 500 No. 1
837		Meadow Brook-Doubs 500 kV
837		Meadow Brook-Pruntytown 500 kV
548	LS Power	502 Junction-Black Oak-Doubs 500 kV
279	NextEra	Black Oak-Stonewall-Goose Creek 500 kV
28		Black Oak-Gore-Goose Creek 500 kV
347		Black Oak-Stonewall-Goose Creek 500 kV
642		Build new 500 kV line from 502 Junction to Black Oak to Stonewall to new Belmont/Gant 500 kV
676		Black Oak-Stonewall-Goose Creek 500 kV
685		Build new 500 kV line from Fort Martin to Black Oak to Stone Wall to Goose Creek
719		Fort Martin to Black Oak to Gore to Goose Creek 500 kV
846		Black Oak-Stonewall-Goose Creek 500 kV
853		Build new 500 kV line from 502 Junction to Black Oak to Stonewall to new Belmont/Gant 500 kV
951		Black Oak-Gore-Goose Creek 500 kV
116		Hunterstown-Doubs 500 kV
255		Hunterstown-Doubs 500 kV
28		Hunterstown-Doubs 500 kV
419		Hunterstown-Doubs 500 kV
445		Hunterstown-Doubs 500 kV
116		Hunterstown-Doubs 500 kV
255		Hunterstown-Doubs 500 kV

Table 7. South Cluster

Proposal ID	Proposing Entity	List Components
711	Dominion	New 500 kV Line (North Anna-Spotsylvania)
711		New 500 kV Line (Spotsylvania to Vint Hill)
711		New 500 kV Line (Vint Hill to Wishing Star)
923		Second 500 kV line from Lexington to Dooms
548	LS Power	Front Royal-VintHill 500 kV
577	NextEra	Front Royal to New Wishing Star sub 500 kV
663		Front Royal to New Wishing Star sub 500 kV
766		Front Royal to New Wishing Star sub 500 kV
325	PSEG	Brambleton-Hinsons Ford 500 kV

Proposal ID	Proposing Entity	List Components
904	TRANSRC	Joshua Falls to Yeat 765 kV

Table 8. Northern Virginia Data Center Cluster

Proposal ID	Proposing Entity	List Components
516	Dominion	Aspen-Doubs Second 500 kV Line | Line No. 514 (Goose Creek-Doubs) Rebuild
692		Aspen-Golden 500 kV Line Build
692		New Mars-Golden 500 kV
692		Aspen to Goose Creek 500 kV
23	FE	Aspen-Doubs Second 500 kV Line | Line No. 514 (Goose Creek-Doubs) Rebuild
837		Aspen-Doubs Second 500 kV Line | Line No. 514 (Goose Creek-Doubs) Rebuild
548	LS Power	Doubs-Goose Creek 500 kV
548		Goose Creek-Beaumeade 500 kV
116	NextEra	Doubs-Gant (new Belmont) 500 kV
255		Doubs-Gant (new Belmont) 500 kV
28		Doubs-Goose Greek 500 kV
419		Doubs-Beaumeade-Goose Creek 500 kV
445		Doubs -Goose Creek 500 kV
846		Doubs-Goose Greek 500 kV
858	TRANSRC	Stork-Flys 500 kV Underground Line

Window 3 Evaluations Process

Consultation Meetings With Proposing Entities

PJM held two rounds of meetings with each of the proposing entities, and the discussions focused on gaining clarity on proposed developments, assumptions, rationale of proposed alternatives and variations. The first round of meetings were conducted in June/July of 2023, and the second round was initiated in late July and concluded mid-August. The latter half of the discussions focused on outage scheduling, routing, risk and cost assumptions and considerations. In addition to the primary two consultation rounds, several additional consultation meetings were organized by PJM with short-listed proposing entities to assist with refining and finalizing the 2022 Window 3 selected proposal list.

Scenario Development

PJM developed scenarios, which were combinations of proposals and/or components from different proposals, addressing all areas of need and evaluated them against the 2027 and 2028 2022 Window 3 base cases. Over 30 scenarios were analyzed for the 2027 model, and over 100 scenarios were developed and analyzed for the 2028 model. Certain scenarios were full combination scenarios submitted by the proposing entities, such as those

submitted by the incumbent Transmission Owners, or other entities including NextEra, LS Power and Transource. PJM also optimized scenarios using components from incumbent and non-incumbent proposing entities. Several scenarios were found adequate to address the needs present in the 2027 analysis; however, the 2028 evaluations show the need for more robust reinforcements in the Eastern cluster and introduced changes to solutions in the Southern cluster. The Western cluster needs are less sensitive, though still impacted by the robustness test. A number of proposals that were developed by proposing entities to address the 2027 needs specifically did not offer the needed scalability and robustness to address the needs posed by the 2028 system conditions. Please refer to the scenario list and abbreviated description provided in Appendix B.

The scenarios were evaluated based on the following principles:

- **Performance**
  - Meeting the system needs of 2027 and being flexible to address 2028 needs
- **Scalability**
  - Scenario/development longevity – system robustness and utilization
- **Impact**
  - Utilization of existing right of way (ROW) where possible and efficient.
- **Validated Cost**
  - Cost evaluation using third-party benchmarking metrics
- **Risks**
  - Triggering additional costs:
    - Substation rebuilds due to extreme short-circuit levels
  - Avoid extended critical outages (Peach Bottom/Conastone rebuilds)
  - Imposing high permitting
  - Inability to meeting in-service date
- **Efficiencies**
  - Avoidance of redundant capital investment including recognizing synergies with EOL facilities and overlaps of previously approved (or imminent) supplemental/baseline upgrades

The scenarios were developed and tested to first address the regional needs and then were refined through new scenarios to address local needs. Scenarios were further refined using more effective proposal components as demonstrated through their performance in the analysis.

2027 Reliability Evaluation Summary

As described earlier on in this report, initial screening was performed on all submitted individual proposals for 2027. These proposals included proposed upgrades at voltage levels of 230 kV to 765 kV. Some of the proposals attempted to address all four cluster needs and were evaluated as standalone scenarios. PJM also developed a scenario by combining the incumbent Transmission Owner proposals, along with further refined scenarios that

utilized select components from various proposals. The 2027 reliability analysis results indicated that all submitted combination proposals could address the 2027 needs to a varying degree. In order to test the robustness of the proposal, PJM evaluated the scenarios on the 2028 cases.

This section outlines the key needs identified as part of the PJM 2022 RTEP Window 3, together with a brief summary of how each of the key proposals addressed those needs in the 2027 study base case scenario.

Eastern Quadrant:

For the eastern quadrant, all submitted proposals acknowledged the need to reinforce the Peach Bottom to Doubs 500 kV transmission corridor via various 230 kV and 500 kV proposals. Generally, all combination proposals submitted by proposing entities addressed the reliability evaluation tests including Gen Deliverability and N-1 analysis with varying degrees. Some of the proposals that did not consider the robustness evaluation requirement part of the PJM 2022 RTEP Window 3 Problem Statement were not designed to handle the higher power transfer demands from the East toward West and hence offered little room beyond meeting the 2027 needs. These proposals are primarily LS Power proposal 548 and Transource combined proposal. Both LS Power and Transource indicated that their proposed solutions were neither designed considering the 2028 robustness and needs base case scenarios nor tested against the 2028 cases.

Exelon proposal 344/660, PSEG proposal 229, 637, 741 ,808, Nextera proposal 217, 385, 445, 728, 948, PPL proposal 374 and Ls Power proposal 548 all proposed 500 kV transmission line developments to address the debottlenecking need of the Peach Bottom to Conastone corridor as well as provide additional supply into the northern Virginia system.

Western Quadrant:

In the west, three proposing entities (First Energy, Nextera and LS Power) offered 500 kV transmission developments to address the higher APS to northern Virginia (West to East) transfer capability needs. One entity (Transource) proposed a 765 kV development. All of these developments proved adequate, from a technical transfer capability perspective, in addressing the identified needs in the western quadrant either in combination or individually.

It is to be noted that although the proposed 765 kV development by Transource has merits from diversifying the West-East transfer path over a wider geographic area, it does pose its own routing, siting and construction risks that may delay meeting the needs in the area in 2027 or as close to that timeline as possible.

Other smaller proposal components, such as the Front Royal to Wishing Star/Loudon area 500 kV developments by Nextera (proposal numbers: 766, 577, 663), offer limited transfer enhancements once the needed bulk transmission reinforcements are in place. These developments, as outlined in the PJM constructability evaluation report pose much higher elevated construction risk and when compared to the limited incremental transfer capability offered were dropped from further consideration.

Southern Quadrant:

The 2027 analysis indicated that the proposed 500 kV line rebuilds in the existing 500 kV corridor currently running between Front Royal and Vint Hill are effective in addressing the identified overloads under the 2027 scenario. LS Power also proposed to build a new, greenfield 500 kV line along that corridor to enhance its transfer capability, which was proven also effective technically. It is to be noted, however, that the 2022 RTEP Window 3, 2027 basecase scenario adopted the older PJM generation dispatch and deliverability rules (in effect at the time) where each load zone tends to hold its import interchange with the rest of the PJM system constant at historical levels. With the much higher and material load increase forecasted in Dominion and APS (up to 7,500 MW), this is difficult to

justify and would require the local generation within Dominion to be dispatched up or close to their maximum capability. This higher Dominion dispatch affects the flows along the 500 kV corridor between North Anna and Morrisville 500 kV substations. With a more reasonable dispatch pattern, according to PJM's new block dispatch methodology, the higher South-to-North flow will drop in the 2028 robustness test scenarios, as further highlighted in the following section.

2027/28 Reliability Evaluation Summary

The 2028 case for the 2023 RTEP was still under development when the 2022 Window 3 opened, and once preliminary study results were available, PJM shared the results with stakeholders at the April 2023 special TEAC.

The 2028 evaluation indicated the need for further regional transfer reinforcements, beyond those offered through the 2027 and changes to a number of needs, particularly within the southern region due to:

- Major deactivation requests in the study area (e.g., Brandon Shores, among others)
- Higher regional transfers as a result of the new block dispatch and generator deliverability test

For this reason, PJM utilized the 2027/28 cases to further assess the robustness of the proposals. The LS Power (proposal 548), NextEra (proposal 598) and Transource (proposal combo) combination proposals did not prove effective in the 2027/28 initial testing. However, PJM further tested the components of LS Power and Transource proposals in developing additional scenarios. NextEra proposed a standalone add-on component upgrade to its 2027 combination proposal (proposal 598) to address 2028 needs through proposal No. 175. PJM evaluations showed that the NextEra proposal 175 and the incumbent Transmission Owners (Exelon, FirstEnergy and Dominion) combination proposal scenarios showed promising performance, and thus were used as starting points for further scenario development and assessments.

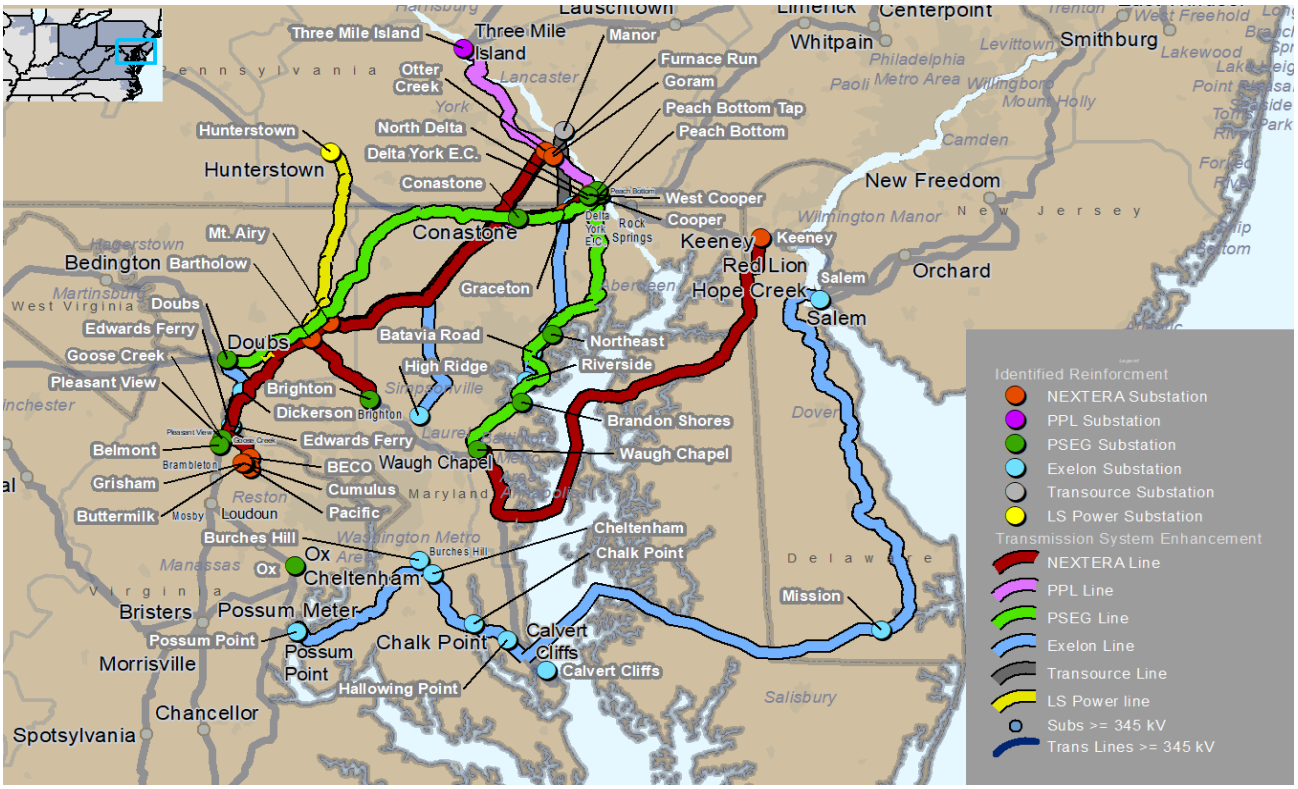
PJM evaluated every proposal individually, as well as various combinations of the proposals and components to identify the most effective solution. Based on different combinations of scenarios performed, PJM identified the need for three regional/local transmission solutions in the East cluster, and results are reflected in the short-listed scenarios.

East Proposal Cluster

Six proposing entities submitted over 15 proposals to address the East cluster violations, as illustrated in **Map 3**. During the window evaluations, PJM confirmed the need for regional and local reinforcements into the BGE system, along with regional reinforcements between Peach Bottom and northern Virginia.

PJM evaluated every proposal individually, as well as various combinations of the proposals and components to identify the more efficient or cost-effective solution. Based on different combinations of scenarios performed, PJM identified the need for three regional/local transmission solutions in the East cluster, which are reflected in the short-listed scenarios.

Map 3. East Proposal Cluster Map



*NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should **not** be relied upon for exact geographical substation locations or line routes.*

Listed below are groups of solutions evaluated as potential solutions to address the BGE local as well as regional transfers:

Solutions evaluated to address BGE local/regional

- **North Delta-High Ridge 500 kV (proposal ID 344/660):**

Approximately a 67-mile AC overhead line proposed by Exelon, the incumbent Transmission Owner. One hundred percent of the line will utilize existing ROW. The solution addresses all of the BGE violations and a majority of the violations due to transfer limitations. The proposed cost is approximately $550 million.

- **Peach Bottom/N. Delta-Raphael-Waugh Chapel 500 kV (Proposal ID 808):**

Approximately a 72-mile AC overhead line proposed by PSEG. The line would be greenfield and require new ROW (a portion of the circuit will parallel existing ROW). The solution will require additional upgrade(s), and there are potential short-circuit issues at Peach Bottom substation that will require rebuilding of the substation. The proposed cost is approximately $511 million in addition to any substation components included in the proposal.

- **Peach Bottom-Brandon Shore 500 kV (Proposal ID 741):**

Approximately a 56-mile AC overhead line proposed by PSEG. The line would be greenfield and require new ROW, majority of which will parallel existing ROW. The solution is comparable to the Exelon solution; however, there are potential short-circuit issues at Peach Bottom substation that will require rebuilding of the substation. The proposed cost is approximately $434 million in addition to any substation components included in the proposal.

- **Keeney-Waugh Chapel 230 kV double circuit (Proposal ID 948):**

Approximately a 73-mile AC overhead line, along with 31 miles of submarine cable, solution proposed by NextEra. The line would be greenfield and require new ROW (approximately 15% of the length would parallel existing ROW). Not only would the solution require additional upgrades to address the BGE local and regional needs, it has a proposed cost of over $4 billion.

Solutions evaluated to address BGE local area solutions (focused on Brandon Shores deactivation)

- **Graceton-Batavia double circuit 230 kV (Proposal ID 344/660):**

Approximately a 29-mile AC overhead line proposed by Exelon, the incumbent Transmission Owner. The solution will be adjacent to an existing circuit, will utilize an existing ROW, and addresses the majority of the local needs. The proposed cost is approximately $195 million.

- **Peach Bottom/N. Delta-Raphael-Waugh Chapel 500 kV *(Proposal ID 808)*:**

The same notes as described above in the "BGE Local/Regional Solutions" section for the same line would apply.

- **Peach Bottom-Brandon Shore 500 kV (Proposal ID 741):**

The same notes as described above in the "BGE Local/Regional Solutions" section for the same line would apply.

- **Keeney-Waugh Chapel 230 kV double circuit (Proposal ID 948):**

The same notes as described above in the "BGE Local/Regional Solutions" section for the same line would apply.

Listed below are solutions evaluated by PJM to address the regional transfer needs, mainly related to transfer to northern Virginia/APS areas:

Proposals evaluated to address regional transfer

- **Peach Bottom-Graceton-Conastone/N. Delta 500 kV upgrade (Proposal ID 344/660):**

A solution proposed by both Exelon and Transource that builds a new 500 kV substation (N. Delta) in the Peach Bottom area and reconfigures the Peach Bottom substation to avoid short-circuit issues that require the Peach Bottom station rebuild. The project includes a new Peach Bottom-Graceton 500 kV, Peach Bottom-N. Delta 500 kV, and N. Delta-High Ridge 500 kV lines, resulting in approximately 75 miles of new transmission that utilizes the existing ROW for the majority of the length, rebuilding of an existing 500 kV line from Peach Bottom-Conastone.

- **Peach Bottom-Doubs 500 kV (Proposal ID 741/808):**

Approximately 87 miles AC overhead greenfield line proposed by PSEG. This solution does not address the Peach Bottom short-circuit issue along with space constraints at the substation.

- **Conastone-Doubs 500 kV (Proposal ID 637):**

Approximately 69 miles AC overhead greenfield with small portion paralleling an existing line proposed by PSEG. The project along with the PPL-proposed project 374 provides the needed transfer capability into the northern Virginia area.

- **Otter Creek-Conastone 500 kV (Proposal ID 374):**

Approximately 17 miles AC overhead line proposed by PPL. The line will expand existing ROW to build the line. The Otter Creek-Conastone 500 kV line will tie in to the PSEG proposed Conastone-Doubs, bypassing the Conastone substation.

- **Hunterstown-Green Valley 500 kV (Proposal ID 229):**

Approximately a 40 miles AC overhead greenfield line proposed by PSEG. The Hunterstown termination causes 500 kV overloads in the Peach Bottom area. The proposal also results in short-circuit issues at Conastone substation, requiring a substation rebuild.

- **Hunterstown-Doubs-Goose Creek 500 kV (Proposal ID 548/846):**

This path is proposed by NextEra and LS Power. The NextEra proposal includes approximately 71 miles AC overhead greenfield line from Hunterstown-Doubs 500 kV, with 25% of the new ROW paralleling existing ROW. The Doubs-Groose Creek 500 kV section would be approximately 19 miles of greenfield line, 20% of which will be underground. The LS Power proposal includes approximately a 66-mile AC overhead Hunterstown-Doubs 500 kV line, of which, 20 miles would utilize existing ROW. The Doubs-Groose Creek 500 kV section would be approximately 18 miles, of which eight miles would utilize existing ROW. The lines out of the Hunterstown-Doubs cause violations on the PECO and BGE system requiring additional upgrades.

- **Otter Creek-T-Point 500 kV (Proposal ID 948):**

Approximately a 61-mile AC overhead greenfield line paralleling existing ROW proposed by NextEra. The solution results in short-circuit issues at Conastone substation requiring rebuild of the station.

- **Barnhart (Hunterstown-Conastone Tap)-T-Point 500 kV *(Proposal ID 728)*:**

Approximately a 37 mile AC overhead greenfield line, 5% of which is paralleling existing ROW, proposed by NextEra. The solution results in short-circuit issues at Conastone substation requiring rebuild of the station.

- **N. Delta-Conastone 500 kV (Proposal ID 217/385/530/564/548):**

This path is proposed by NextEra and LS Power, both of which are approximately 15 miles. The majority of the ROW parallels existing ROW or utilizes existing ROW. Exelon who is the owner of the ROW is utilizing the same ROW in their proposal.

- **T-Point-Data Center Alley 230 kV (Proposal ID 728):**

Approximately a 35-mile two greenfield single 230 kV circuits proposed by NextEra. Of the total length, 95% is AC overhead, and the remaining 5% would be underground. The 230 kV system can't be built without the 500 kV T-Point, which will cause a short-circuit issue at Conastone substation requiring the Conastone station rebuild.

- **Transource 230 kV development between Peach Bottom and Conastone (Proposal ID 487–IEC East):**

Scope includes Transource's 500/230 kV developments between Peach Bottom and Conastone. The project doesn't address the BGE local need.

Proposals evaluated to address PA/MD tie lines

- **Transource 230 kV development between New Rice-Ringgold (Proposal ID 487- IEC West):**

Scope includes Transource's new 500/230 kV Rice substation (tie into Vinco-Hunterstown 500 kV circuit) and approximately 29 miles of new double circuit 230 kV AC overhead greenfield transmission line between Rice and Ringgold (FE station).

- **First Energy new Hunterstown-Carroll 230 kV (Proposal ID 837)**

The project includes approximately 24 miles of rebuilding an existing Hunterstown-Carroll 115/138 circuit to 230 kV double circuit construction.

West Proposal Cluster

Four proposing entities submitted solutions to address the West cluster violations, as illustrated in **Map 4**. All proposals approached the West needs through new 500 kV or 765 kV lines.

Regional Solutions

- **502 Junction-Black Oak-Stonewall-New Belmont (Gant) 500 kV: (NextEra)**

Approximately 67 miles of one 500 kV line on existing or parallel to existing ROW to Black Oak 500 kV substation. The next portion of the line will be approximately 53 miles long terminating at Stonewall substation to existing or parallel to existing ROW. PJM's analysis did not show additional benefits of looping the line into Black Oak 500 kV substation. The 500 kV line will continue east for roughly 22 miles on existing or parallel to existing ROW before turning south for 25 miles as greenfield development to be terminated at New Belmont/Gant 500 kV substation.

- **Fort Martin-Doubs 500 kV double/single circuits: (FE)**

Construct approximately 158 miles of new 500 kV (double/single) line(s) from Fort Martin 500 kV substation to Doubs 500 kV substation. The new transmission line will require installation of new 500 kV breakers at Doubs and Fort Martin 500 kV substation and the expansion of Doubs 500 kV substation.

- **Pruntytown-Mt. Storm and Meadow Brook-Doubs 500 kV: (FE)**

- Construct approximately 50 miles of new 500 kV line from Pruntytown 500 kV substation to structure No. 5 of on the Meadow Brook to Mount Storm 500 kV line located adjacent to Mt. Storm 500 kV substation. Cut the existing Meadow Brook 500 kV to Mount Storm 500 kV line from the Mount Storm line terminal, and connect the new 500 kV line from Pruntytown 500 kV substation. The new transmission line will require expansion of Pruntytown 500 kV substation.

- Constuct approximately 55 miles of new 500 kV line from Meadowbrook 500 kV substation to Doubs 500 kV substation. Reterminate existing Meadow Brook to Loudon 500 kV line and existing Meadow Brook to Front Royal 500 kV line. The new transmission line will require installation of new 500 kV breakers at Doubs and Meadow Brook 500 kV substation and the expansion of Doubs 500 kV substation.

- **502 Junction-Black Oak-Doubs 500 kV: (LS Power)**

Construct approximately 73 miles of new 500 kV line from 502 Junction 500 kV substation to Black Oak 500 kV substation. Construct approximately 72 miles of new 500 kV line from Black Oak 500 kV substation to Doubs 500 kV substation. Approximately 52 miles of the 72-mile line will be built by rebuilding the existing 138 kV circuit to a double 500/138 kV circuit.

- **Joshua Falls-Yeat 765 kV: (Transource)**

Construct approximately 135 miles of new 765 kV line from existing Joshua Falls 765 kV substation to a new Yeat 765 kV substation. The new transmission line will require installation of new 765 kV breakers at Joshua Falls 765 kV substation.

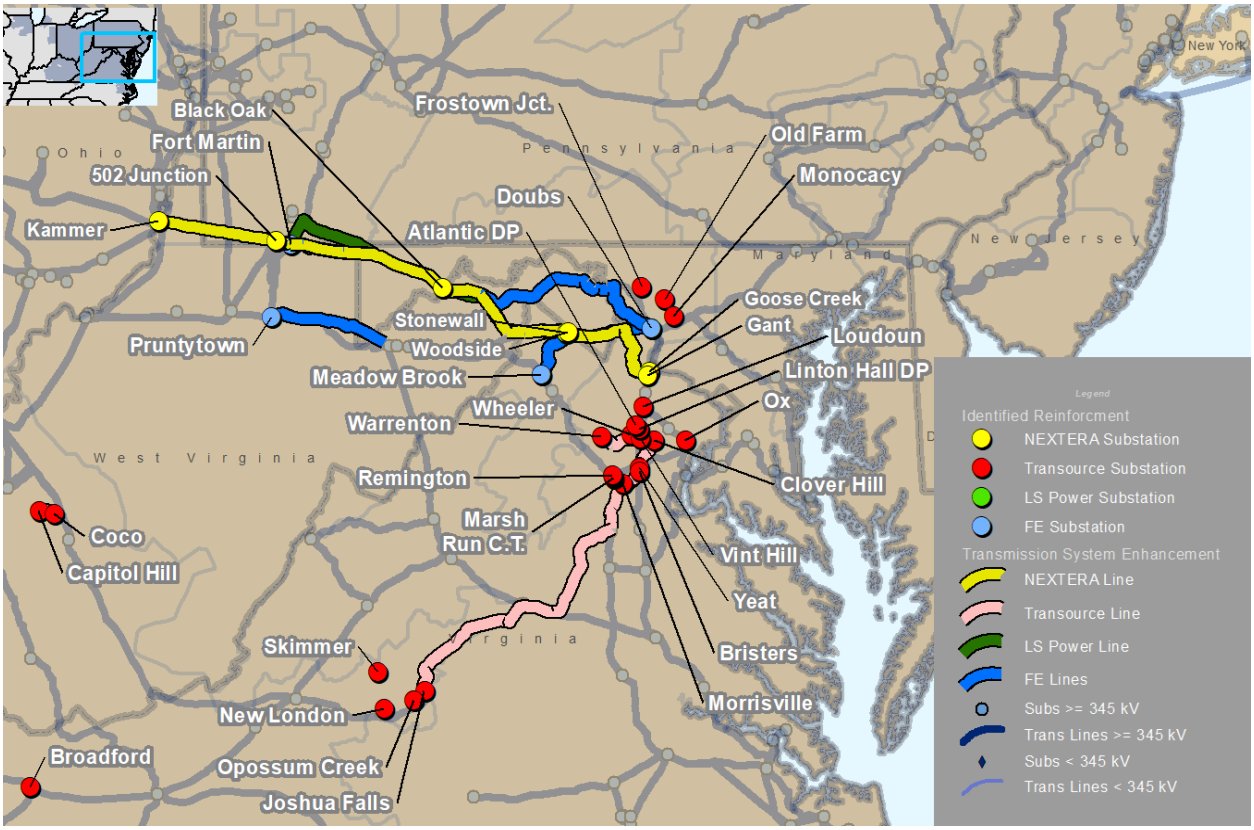
The above-proposed 500 kV solutions, regardless of proposing entity, overlapped in terms of proposed ROW with the exception of First Energy's proposal of new line from Pruntytown-Mt. Storm and Meadow Brook-Doubs. PJM also tested less effective/efficient solutions, two examples of which are provided below:

- Front Royal-New Wishing Star 500 kV: (NextEra)

- Black Oak-Goose Creek 500 kV: (NextEra)

PJM evaluated every proposal individually, as well as various combinations of the proposals and components to identify the most effective solution. Based on different combinations of scenarios performed, PJM identified that with adequate reinforcements in the East (three lines), only one 500 kV or 765 kV line with dedicated dynamic VAR support would be required. For the 500 kV reinforcement options terminating at Doubs, additional transfer capability would be required into Goose Creek (Northern VA area).

Map 4. West Proposal Cluster Map



*NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should **not** be relied upon for exact geographical substation locations or line routes.*

South Proposal Cluster

Four proposing entities submitted solutions to address the South cluster violations, as illustrated in **Map 5**. All proposals approached the South needs primarily through new 500 kV lines.

Regional Solutions

- **Front Royal-New Wishing Star (Racefield) 500 kV: (NextEra)**

Approximately a 48-mile AC overhead line proposed by NextEra with about 70% greenfield ROW, 25% adjacent to road ROW and 5% an expansion of existing transmission ROW. This solution is the most direct route, from west to east, into the Loudoun area and is similar in nature to the originally proposed Trail project (Meadow Brook-Loudoun). The Trail project was a 500 kV line proposed by Dominion and Allegheny Power, through their subsidiary TrAILCo. It began in western Pennsylvania, crossed through West Virginia, and into Loudoun County, Virginia. Due to the amount of opposition at the time, the line took a much longer route heading south toward Morrisville before heading back up to Loudoun. PJM performed sensitives with and without the new Front Royal-New Wishing Star 500 kV line and did not see a substantial impact on solved violations. PJM believes obtaining new ROW will be difficult following the TrAILCo project.

- **Front Royal-Vint Hill 500 kV: (NextEra)**

Approximately a 64-mile AC overhead greenfield line proposed by LS Power. The line primarily parallels existing ROW along Front Royal-Morrisville and Meadow Brook-Vint Hill (previously Loudoun).

- **Hinsons Ford Rd-Brambleton 500 kV: (PSEG)**

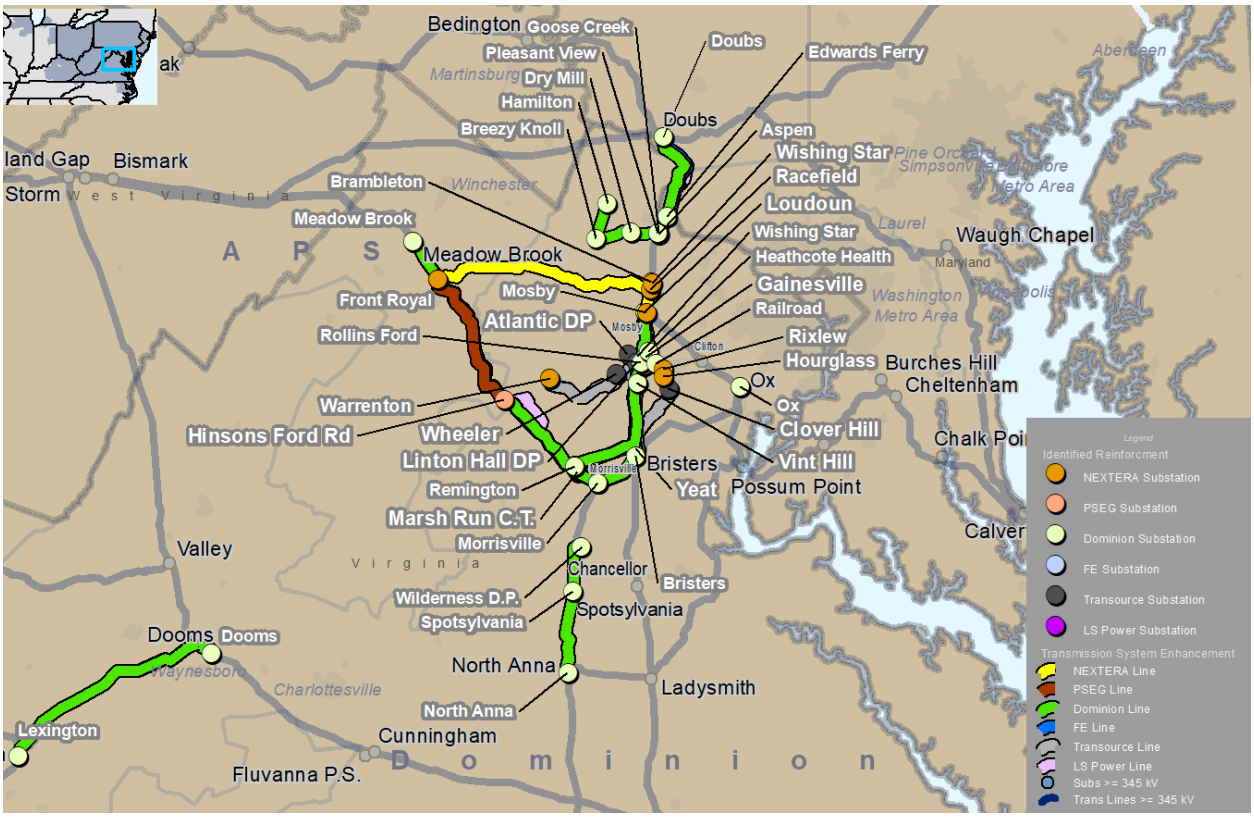
Approximately 34-mile AC overhead greenfield line proposed by PSEG. The proposal shows some similarities to the two above proposals by NextEra and LS Power. While not going directly from west to east or travels as far south to Morrisville, the line would cut across to Brambleton/Loudon area.

- **North Anna-Wishing Star 500 kV: (Dominion)**

The Dominion solution brings a 500 kV line from North Anna all the way up to Wishing Star connecting to Spotsylvania and Vint Hill along the way. In order to fit the additional 500 kV line in their existing corridor, Dominion would wreck and rebuild structures from Morrisville to Wishing Star, which will impact two 500 kV and two 230 kV lines. The North Anna-Spotsylvania section is approximately a 14 mile, the Spotsylvania-Vint Hill section is approximately 38 miles and the Vint Hill-Wishing Star section is approximately 17 miles, all of which would be new AC overhead lines using existing ROW. However, PJM observed that some violations seen in the 2027 results are not present in 2028, likely due to the assumption and methodology changes, and so it may not be necessary to go as far south as North Anna, but rather start at Morrisville instead.

PJM evaluated every proposal individually, as well as various combinations of the proposals and components to identify the most effective solution.

Map 5. South Proposal Cluster Map



*NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should **not** be relied upon for exact geographical substation locations or line routes.*

Northern Virginia Data Center Cluster

Three proposing entities submitted solutions to address the Northern VA data center cluster violations, as illustrated in **Map 6**. Proposals approached the data center needs primarily either through underground 500 kV cables or an overhead 500 kV and 230 kV line.

Data Center Alley Solutions

- **Goose Creek-Beaumeade 500 kV underground (LS Power) – 2308/3596 MVA for SN/SE**

Approximately a 5-mile greenfield underground double circuit cable proposed by LS Power. The proposal would expand Dominion's existing Goose Creek and Beaumeade substations to accommodate the new line. LS Power proposes to follow the W&OD Trail in which Dominion currently owns the ROW.

- **Stork-Flys 500 kV underground:**

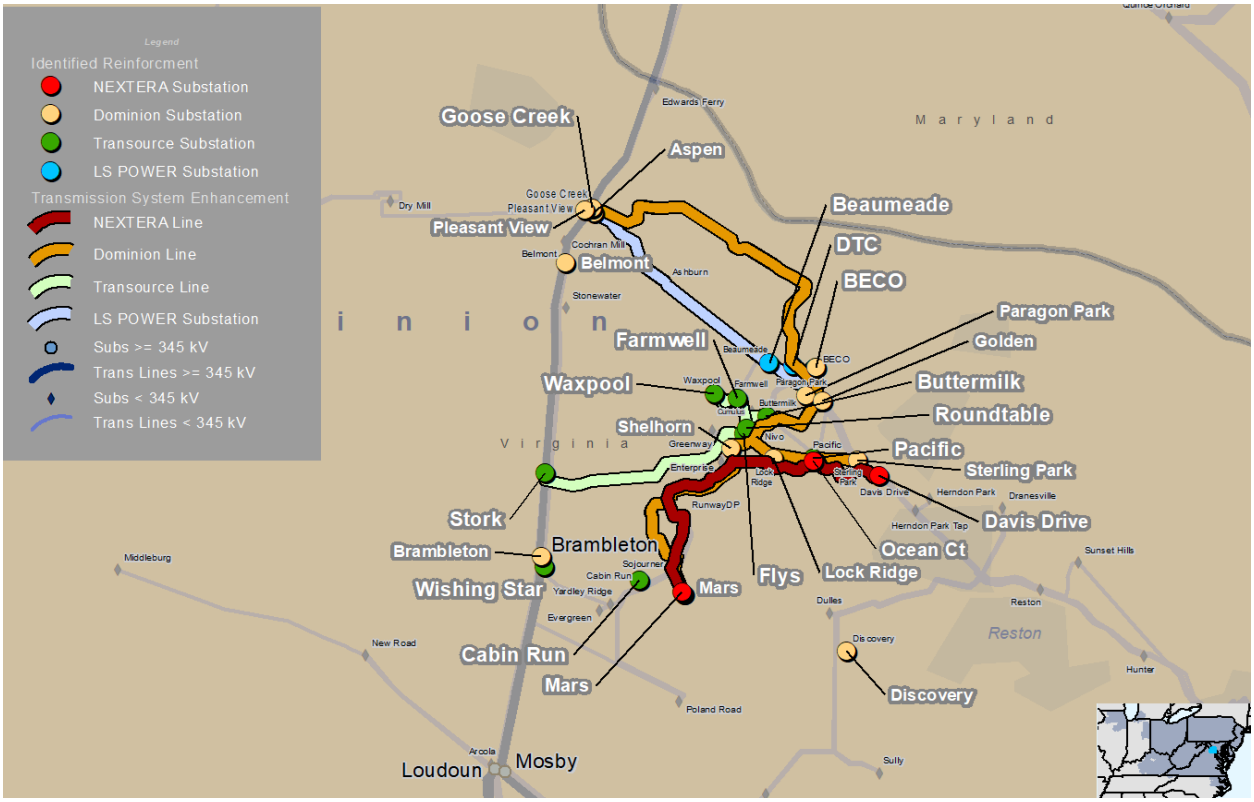
Approximately a 5-mile greenfield underground cable proposed by Transource. The line would be built along the center median of a road. The summer normal and emergency ratings would be 3302/3302 MVA (SN/SE)

- **Aspen-Golden-Mars 500/230 kV overhead (Dominion) – 4357/4357 MVA for SN/SE**

The proposal builds a new Aspen substation adjacent to Goose Creek, along with another new substation called Golden southeast of Aspen. The new line would start at Aspen, move southeast toward Golden, and then eventually close the 500 kV ring around the data center area to Mars. The Aspen-Golden section of the line would be approximately 8.5 miles, and the Golden-Mars section would be approximately 8.3 miles, both of which would be 500 kV AC overhead with 230 kV underneath. The project cost is approximately $1 billion.

PJM evaluated every proposal individually, as well as various combinations of the proposals and components to identify the most effective solution. All three proposals have comparable performance in terms of solving the violations in the Data Center Alley area.

Map 6. Northern VA Data Center (Data Center Alley) Proposal Cluster Map



*NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should **not** be relied upon for exact geographical substation locations or line routes.*

Short-Circuit Analysis

Drivers for the 2022 Window 3 are reliability violations stemming from load flow analysis, not short-circuit analysis. Short-circuit analysis followed a screening process to support the 2022 Window 3 evaluation of proposals. The short-circuit screening identified potential additional scope attributed to overduty breakers, and potential switchyard rebuilds. Short-circuit analysis was applied holistically, where the scenario under study was comprised of one or more proposals, designed to address all Window violations at once which ensures accounting for all short-circuit contributions by all proposed solution facilities of each scenario.

The screening process considered 11 separate TO breaker sets[2] using the window posted 2027 baseline case, then analyzed the proposals and scenarios using a single Aspen OSF (Options Settings File) based on PECO's study parameters. Short-circuit screening was performed on all scenarios deemed promising based on power flow analysis results and on the final selected proposals base case.

As part of the scenario screening process, breakers identified as overduty attributed to the scenario under study were reviewed. For proposals that included breaker replacements, those breakers were reviewed for adequacy of their proposed interrupting capability. The study also identified breakers that became overdutied as a consequence of the scenario under study, but were not addressed in the individual proposals received by PJM. If replacing the consequential overduty breaker with a breaker having a greater interrupting capability could remediate the overduty condition, then the cost of the breaker replacement was factored into the overall scenario cost.

However, in some scenarios, the identified fault level increase was quite high, exceeding the ratings of the substation ground grid and other fault-sensitive facilities within the substation. In these situations, simply upsizing the breaker does not fully address the high fault level violation. For example, at the Conastone 500 kV yard, excessively high fault level would require the entire substation to be rebuilt.

The Peach Bottom 500 kV North and South yards were also monitored closely. Remediation of excessively high fault levels could require a long duration outage of the 500 kV Peach Bottom switchyards, which may impact the availability and operability of the Peach Bottom nuclear plant during the rebuild if so required. Scenarios that created excessively high fault levels at either Conastone or Peach Bottom were hence flagged, and impacts to both cost and schedule factors were given due consideration when evaluation feasibility of proposed solutions.

The 2022 Window 3 selected scenario underwent a subsequent short-circuit analysis more rigorous than the short-circuit screening. An Aspen Breaker Duty Report, using the native TO Option Settings File, was generated for each TO area where overduty breakers were identified in the initial screening. Results were shared with the impacted TOs for validation and breaker replacement cost estimation.

Objectives of the short-circuit analysis were achieved with the 2022 Window 3 selected scenario. Neither the Conastone nor Peach Bottom substations were impacted for excessively high fault levels that exceed the existing short-circuit capability reported by the transmission owner. There were, however, 36 breakers identified as overdutied, which were not included in the submitted proposals. These breakers are located in APS and Dominion substations at nominal voltages of 138kV, 230 kV and 500 kV. Costs to remediate these overduty breakers are incorporated into the selected scenario cost estimate.

[2] AE-DPL, AEP, APS, ATSI, FirstEnergy(JCPL-MetEd-Penelec), BGE, DOM, PECO, PEPCO, PPL, PSEG

Table 9. Identified Circuit Breaker Upgrades/Replacements (beyond those proposed by proposing entities)

TO Area	Substation	kV	BREAKER (Qty)
APS	Double Toll Gate	138	1
	Doubs	500	1
DOM	Ashburn	230	1
	Beaumeade	230	1
	Beco	230	2
	Belmont	230	1
	Brambleton	230	6
	Gainesville	230	1
	Loudon	230	2
	Ox	230	7
	Paragon Park	230	4
	Reston	230	1
	Stonewater	230	4
	Waxpool	230	4

Load Deliverability Analysis

Load Deliverability is one of the studies conducted in evaluating the 2022 Window 3 proposals. PJM performed the load deliverability analysis to determine the increased CETL (Capacity Emergency Transfer Limit) enabled by the proposed proposals individually and in combination within a specific scenario. The CETL Calculation focused on specific LDAs based on the potential impact of the 2022 Window 3 proposals on the transfer limit to the LDAs. PJM selected APS, BGE, Dominion and SWMAAC LDAs for evaluation.

The load deliverability analysis was performed according to PJM Manual 14B requirements.[3] The study was conducted using the 2023 series RTEP 2028 base case, with 2022 Window 3 scenario solutions applied.

PJM conducted the CETL test on the short-list scenarios and observed the following:

- The APS CETL/CETO margin is well above 115% for all scenarios and the CETL value is comparable.

The NextEra Proposal 175:

- The CETL/CETO for the SWMAAC is <115%, while the CETL/CETO for BGE barely meeting 100%.

PJM Combined Proposal 500 kV or 765 kV Option:

- The CETL/CETO margin for BGE, SWMAAC and Dominion LDA are well above 115%.

PJM examined the Dominion CETL for different components related to the West 500 kV proposals, including the First Energy proposed ID 837 solution. The analysis has identified the need to terminate the West solution into the Dominion Data Center vicinity, as such the NextEra proposal ID 853 option yielded higher CETL.

The CETL study result also revealed the addition of the Otter Creek-Doubs 500 kV line increases the Dominion CETL by ≈20%.

[3] PJM Manual 14B: PJM Region Transmission Planning Process: https://www.pjm.com/~/media/documents/manuals/m14b.ashx

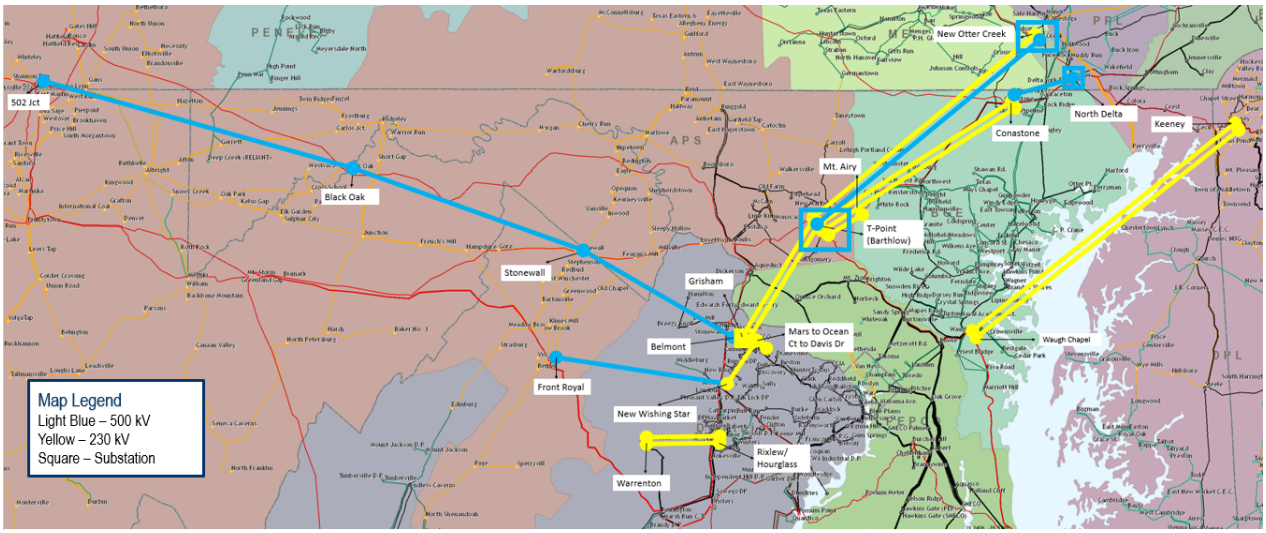
Selection of Short-Listed Scenarios and Proposal Components

Scenarios listed below represent the initial short list of scenarios presented at the October 3, 2023, TEAC. The merits and shortcomings of each are further detailed along with a very high-level point-to-point illustration of the project components on the associated maps.

NextEra Proposal 175

The simplified map illustration below in **Map 7** summarizes the high-level scope of the NextEra proposal 175 designed to address 2028 needs. The proposal from an analytical perspective appears to address the needs identified on the system; however, the majority of the lines are greenfield, some of which cross sensitive areas such as Front Royale-Wishing Star in the West and the Chesapeake Bay crossing in the South. The proposal as a whole, while theoretically may appear acceptable, results in a considerably higher-risk profile and does not have significant cost difference to the two scenarios that PJM built using a combination of proposal and components.

Map 7. NextEra Proposal 175



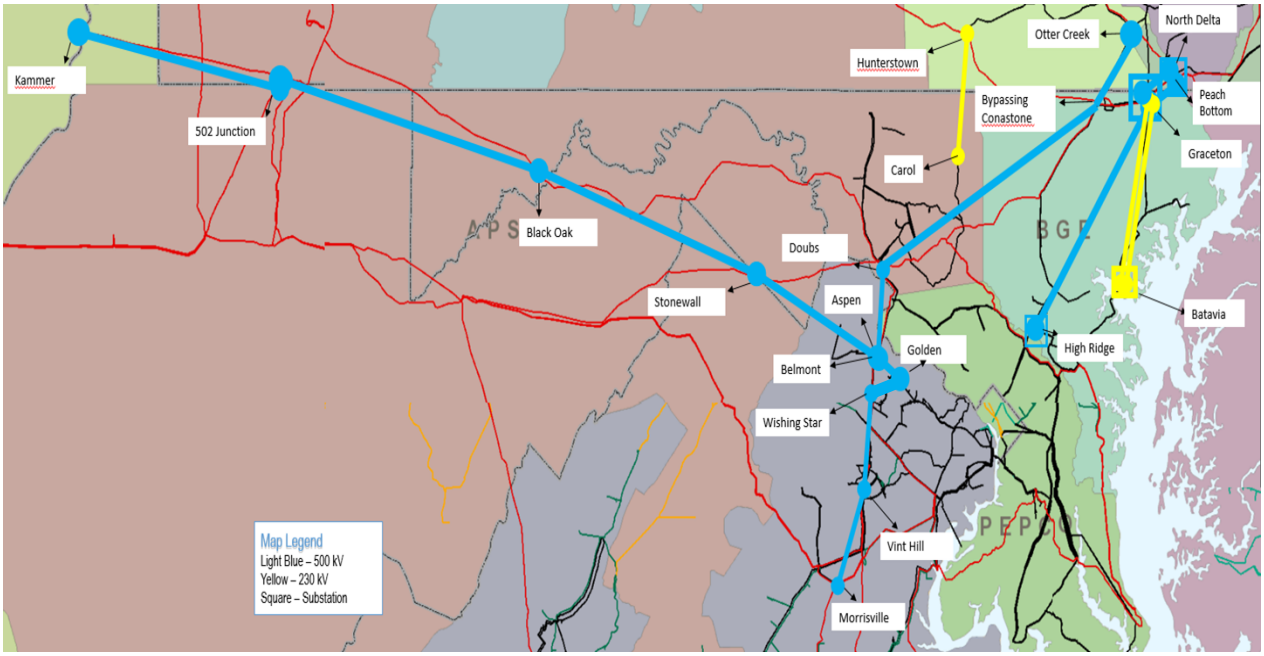
*NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should **not** be relied upon for exact geographical substation locations or line routes.*

PJM Combination – 500 kV Scenario

The simplified map illustration below in **Map 8** summarizes the high-level scenario designed by PJM to address 2028 needs. The scenario includes proposal components from both incumbent Transmission Owners (Dominion, Exelon, FirstEnergy and PPL) and non-incumbent entities (NextEra and PSEG). The scenario attempts to address the reliability needs with less impact on sensitive geographic areas at a comparable cost. The scenario results in overall lower land and social impacts due to the number of circuits proposed at the appropriate voltage level, including two 500 kV lines in the East and only a single 500 kV line in the West, combined with Dominion local solutions. This scenario includes a non-incumbent 500 kV component in the East that establishes a new 500 kV path between MAAC and the northern Virginia/West area. It is important to note that some of these proposed components were very similar. For example, for the 500 kV reinforcements identified in the West, FirstEnergy, NextEra and LS Power proposed very similar proposals. What is selected in this scenario is NextEra's proposal between 502 Junction to Black Oak to Stonewall to directly into Data Center Alley. This proposal adds one additional 500 kV line between the

APS system and Dominion while also following very similar ROW adjacent to existing facilities. PJM refined this short-listed scenario further in order to come up with the final recommended solution.

Map 8. PJM Combination – 500 kV Scenario

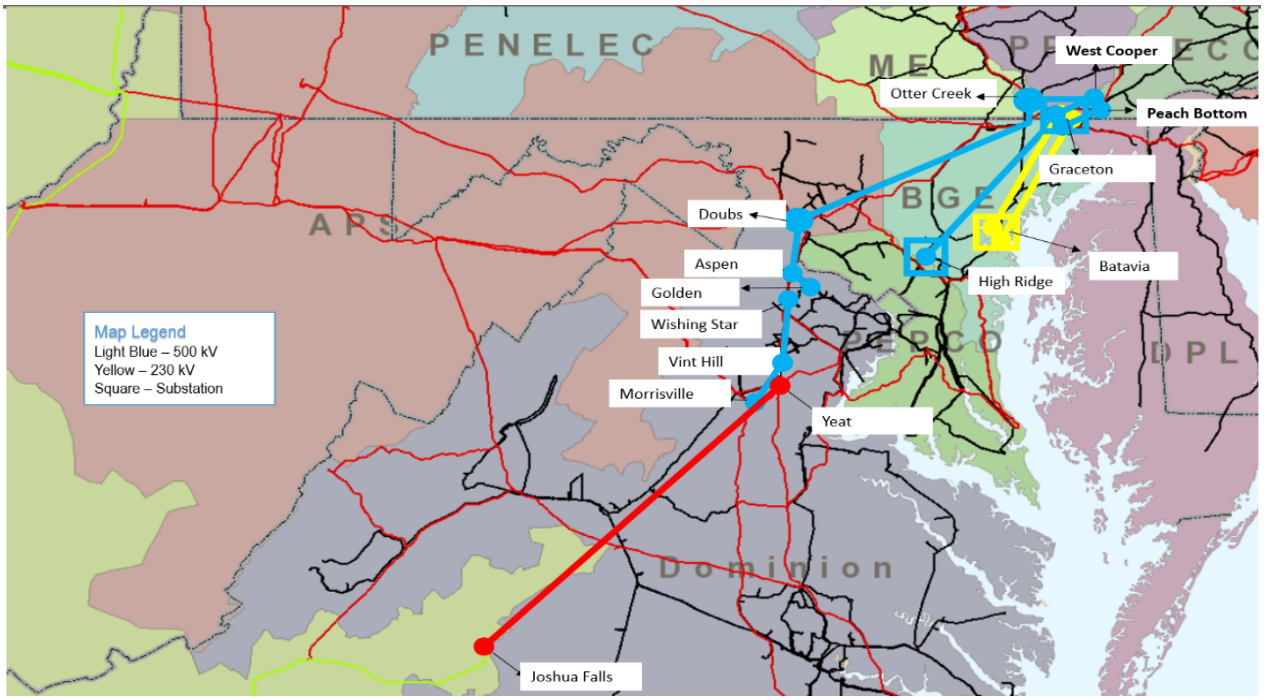


*NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should **not** be relied upon for exact geographical substation locations or line routes.*

PJM Combination – 765 kV Scenario

The simplified map illustration below in **Map 9** summarizes the high-level scenario designed by PJM to address 2028 needs. The scenario primarily replaces the 500 kV developments in the northern West cluster with a 765 kV proposed development by Transource in the South/West. The proposal is performs comparably to meet the system needs, but offers more flexibility to meet needs further in the South as the load growth will likely shift southward in future years. It also provides balanced supply between North and South supply direction rather than concentrating the supply from the North. The 765 kV development also reduces the flow on the four existing 500 kV lines in APS running west-to-east. The main risk for this scenario is the timeline to construct the 765 kV circuit.

Map 9. PJM Combination – 765 kV Scenario



*NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should **not** be relied upon for exact geographical substation locations or line routes.*

Final Reliability Analysis and Recommended Solution

While PJM provided a short list of scenarios at the October 3, 2023, TEAC meeting, PJM since then further refined the 500 kV scenario and presented the recommended solution for 2022 Window 3 at the October 31, 2023, and December 5, 2023, TEAC meetings. This section summarizes the selected set of proposals and associated rationale to address the reliability needs for the 2022 RTEP Window 3. **Table 10** at the end of this section provides summary of evaluation rationale, relevant study scenarios supporting the selection as well as a high-level summary of the scenario build up and analysis.

Eastern Quadrant

As discussed earlier, the eastern quadrant needs primarily focus on; (1) enhancing the east to west bulk power transfers, (2) support the load deliverability and reliability needs for the BGE system and (3) support the additional load demands of the APS and northern Virginia transmission systems where a large amount of load growth is being forecasted.

All three shortlisted scenarios, discussed in the preceding section address this need. However, PJM selected the eastern cluster proposals part of the PJM 500 kV combination scenario to be the most effective and efficient solutions to address those needs for the following reasons;

1. Both the PJM developed 500 kV and 765 kV shortlisted combination scenarios have the same eastern quadrant solutions (cluster).
2. The PJM 500 kV combination scenario offers the needed reliability reinforcements with the least amount of infrastructure development and with much higher reliability margin compared to the NextEra proposal which is both of higher cost and involves developing a significantly higher amount of facilities.
3. The PJM 500 kV combination proposal offers full utilization of existing right of ways, debottlenecking the historically constrained Peach Bottom – Conastone 500 kV transmission corridor.
4. Addresses the load deliverability needs into the BGE system which is further exacerbated by the deactivation of key power plant(s) in the BGE zone. The NextEra proposal fails the load deliverability test for the 2027/28 year while the PJM 500 kV proposal combination meets the reliability needs with a healthy margin to spare following the deactivation of the Brandon Shores plant.

Western Quadrant

The western quadrant reinforcements are critical due to the high demand for west to east power flow and into the APS and northern Virginia networks. This transmission corridor extending from the Kammer 765 kV substation in the West towards the eastern edge of the APS system (Doubs) and the northern edge of the Dominion transmission network (Goose Creek area) was experiencing voltage collapse conditions under the higher transfer demands represented in both the 2027 and 2027/28 scenarios.

Again all shortlisted scenarios address the need for the west to east transfer, either through a single 500 kV (in the north) or 765 kV (in the south) transmission path developments.

The NextEra proposed 500 kV transmission development between 502 Junction in the west towards Stonewall and then terminating into the planned Aspen 500 kV development offers the needed reliability reinforcement to serve both the West to east transfer need and also provide a third 500 kV supply source into the northern Dominion load center region.

The 765 kV development proposed by Transource imposed higher schedule and constructability risk due to its predominantly greenfield nature which will impose an avoidable reliability and operational risks in the northern Virginia and APS areas if the schedule of the project is delayed.

Southern Quadrant

PJM selected the southern cluster part of the PJM 500 kV combination scenario to be the more effective and cost efficient solution to the needs in the southern quadrant. This solution predominantly utilizes the existing 500 kV corridor while meets the reliability and load deliverability needs for the system.

This proposed selection avoids introduced multiple and unnecessary green field developments that may not be effective in the longer term and do not contribute to reinforce the greater 500 kV transmission corridor extending between the Goose Creek area in northern Virginia and the existing Morrisville substation further to the south within the Dominion footprint.

Dominion Quadrant

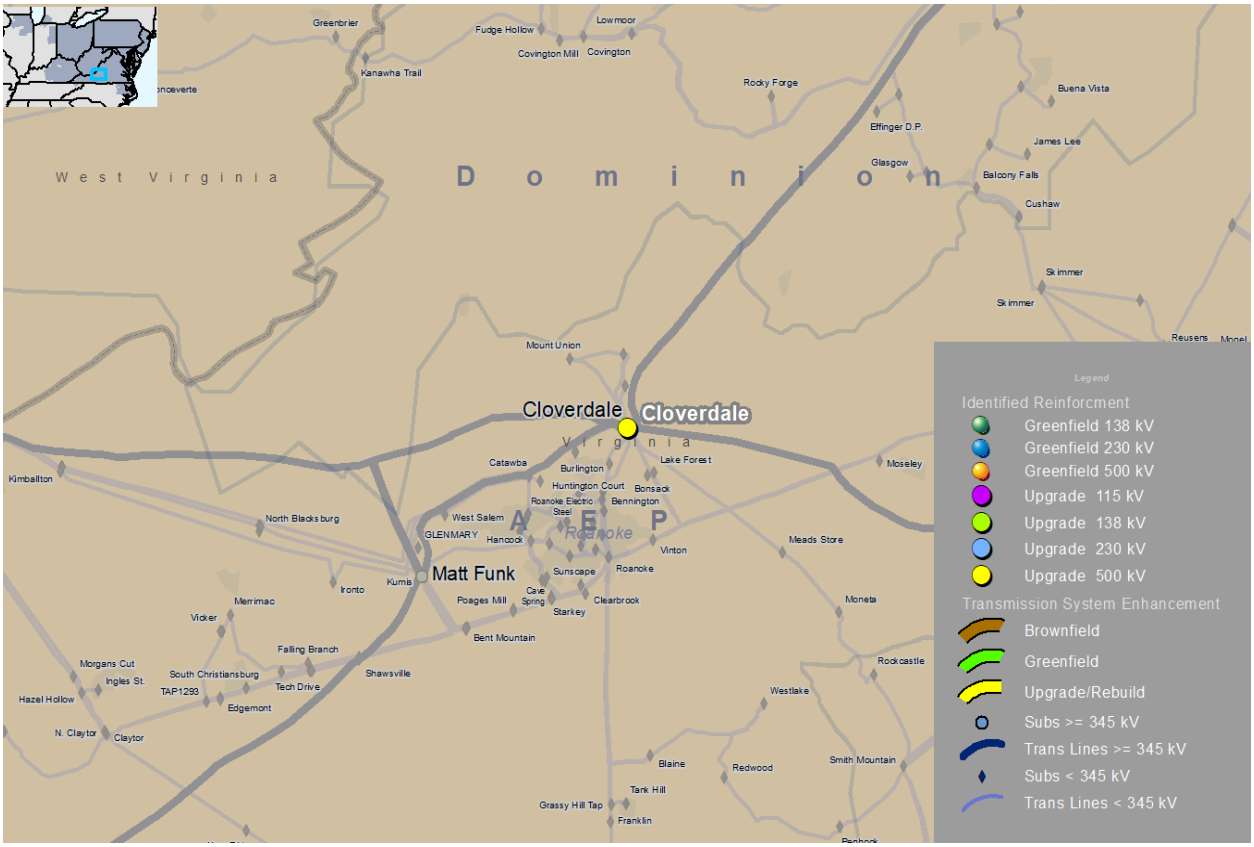
PJM selected the Dominion/northern Virginia cluster of its shortlisted 500 kV combination solution to be the more cost effective and efficient solutions to address the needed reliability needs in northern Virginia. The selected solutions offer the needed local transmission system reinforcement to support the local data center load concentration in northern Virginia and establishes a robust, high capacity overhead transmission line reinforcement through the data center load area. This allows for easy access to integrate load as demand increases and also offers reinforcement to the 500 kV path between Goose Creek and Loundon/Brambelton substations that is currently served via a single 500 kV circuit.

The total cost estimate for the recommended solution is approximately $5,142.98 million. The following sections summarize the selected project components by cluster:

AEP Local

PJM recommends proposal 410 by AEP to address the AEP local area needs. The project will establish a new 500 kV breaker position for the low side of the existing 765/500 kV transformer at Cloverdale station. The new position will be between two new 500 kV circuit breakers located in a new breaker string, electrically converting the 500 kV yard to “double-bus double-breaker” configuration. The estimated cost is $11.59 million, and the required in-service date is June 2027 with a projected in-service date of October 2026. The local transmission owner, AEP will be designated to complete this work.

Map 10. AEP Local Area Improvements



South

PJM recommends a revised scope of proposal 711, proposal 967, proposal 211, proposal 731, partial scope of proposal 74 and proposal 231 proposed by Dominion to address the South cluster needs. There are also a number of additional upgrades identified by PJM.

The revised scope of proposal 711 includes a new Morrisville-Vint Hill-Wishing Star 500 kV line (approximately 36.3 miles) while maximizing the use of existing ROW within this corridor. The project scope also includes wrecking and rebuilding both the 500/230 kV double circuit towers (horizontal, stacked layout) in the Morrisville-Loudoun-Brambleton corridor to free up space for the new single 500 kV monopole within the same corridor. Below is a list of line rebuilds:

- 500 kV Line No. 545 (Bristers-Morrisville) rebuild
- 500 kV Line No. 569 (Loudoun-Morrisville) rebuild
- 500 kV Line No. 535 (Vint Hill-Loudoun) resag/rebuild
- 500 kV Line No. 546 (Mosby-Wishing Star) rebuild
- 500 kV Line No. 590 (Mosby-Wishing Star) rebuild
- 230 kV Line No. 2030 (Gainesville-Loudoun) rebuild

- 230 kV Line No. 2045 (Loudoun-Brambleton) rebuild
- 230 kV Line No. 2094 & 2227 (Brambleton-Racefield-Loudoun) rebuild
- 230 kV Line No. 2101 (Bristers-Vint Hill) rebuild
- 230 kV Line No. 2114 (Remington CT-Rollin Ford) rebuild
- 230 kV Line No. 2140 (Loudoun-Heathcote) rebuild
- 230 kV Line No. 2151 (Railroad DP-Gainesville) rebuild
- 230 kV Line No. 2163 (Vint Hill-Liberty) rebuild
- 230 kV Line No. 2176 (Heathcote-Gainesville) rebuild
- 230 kV Line No. 2222 (Rollins Ford-Gainesville) rebuild
- 115 kV Line No. 183 (Bristers-Ox) rebuild

The project includes substation upgrades at the following substations:

- **Bristers:** Upgrade and install equipment at Bristers substation to support the new conductor 5000A rating for 500 kV Line No. 545.
- **Brambleton:** Upgrade and install equipment at Brambleton substation to support the new conductor termination. All terminal equipment for 230 kV Lines No. 2045 & No. 2094 to be rated for 4000A continuous current rating.
- **Dawkins Branch:** Revise relay settings at 230 kV Dawkins Branch.
- **Gainesville:** Upgrade and install equipment at Gainesville substation to support the new conductor termination. All terminal equipment for 230 kV Line No. 2030 to be rated for 4000A continuous current rating.
- **Heathcote:** Revise relay settings at 230 kV Heathcote.
- **Loudoun:** Upgrade and install equipment at Loudoun substation to support the new conductor 5000A rating for line 569 (500 kV), 2030 (230 kV), 2045 (230 kV), and 2094 (230 kV).
- **Mint Springs:** Revise relay settings at 230 kV Mint Springs.
- **Morrisville:** Upgrade and install equipment at Morrisville substation to support the new 500 kV conductor termination. All terminal equipment to be rated for 5000A for 500 kV Line No. 545 & No. 569. Upgrade 500 kV bus 2 to 5000A.
- **Mosby:** Upgrade and install equipment at Mosby substation to upgrade terminal equipment to be rated for 5000A for line 546 and line 590.
- **North Star:** Revise relay settings at 230 kV North Star.
- **Racefield:** Revise relay settings at 230 kV Racefield.
- **Railroad:** Revise relay settings at 230 kV Railroad.
- **Vint Hill:** Install terminal equipment at Vint Hill substation to support a 500 kV 5000A line to Spotsylvania. Update relay settings for 230 kV Lines No. 2101, No. 2163, and 500 kV Line No. 535.

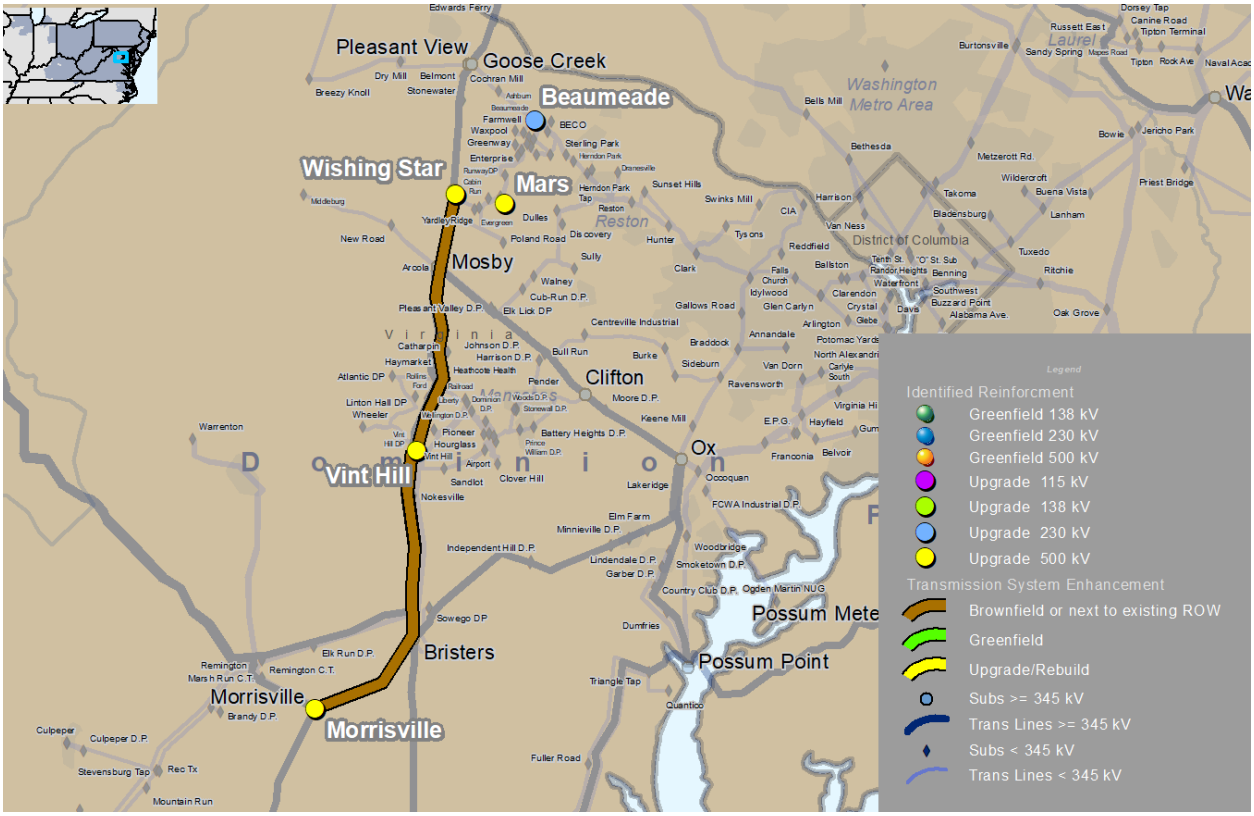
- **Wishing Star:** Install terminal equipment at Wishing Star substation to support a 500 kV 5000A line to Vint Hill. It also provides for new relay settings for 500 kV lines 546 and 590.
- **Youngs Branch:** Revise relay settings at 230 kV Youngs Branch

Breaker upgrades will also be required as follows:

- Replace 4 overdutied 230 kV breakers at Loudoun substation with 80 kA breakers.
- Replace 1 overdutied 500 kV breaker at Ox Substation with a 63 kA breaker.

The estimated cost is $842.19 million, and the required in-service date is June 2027 with a projected in-service date of June 2028. The local transmission owner, Dominion, will be designated to complete this work.

Map 11. South Area Improvements – Revised Scope of Proposal 711

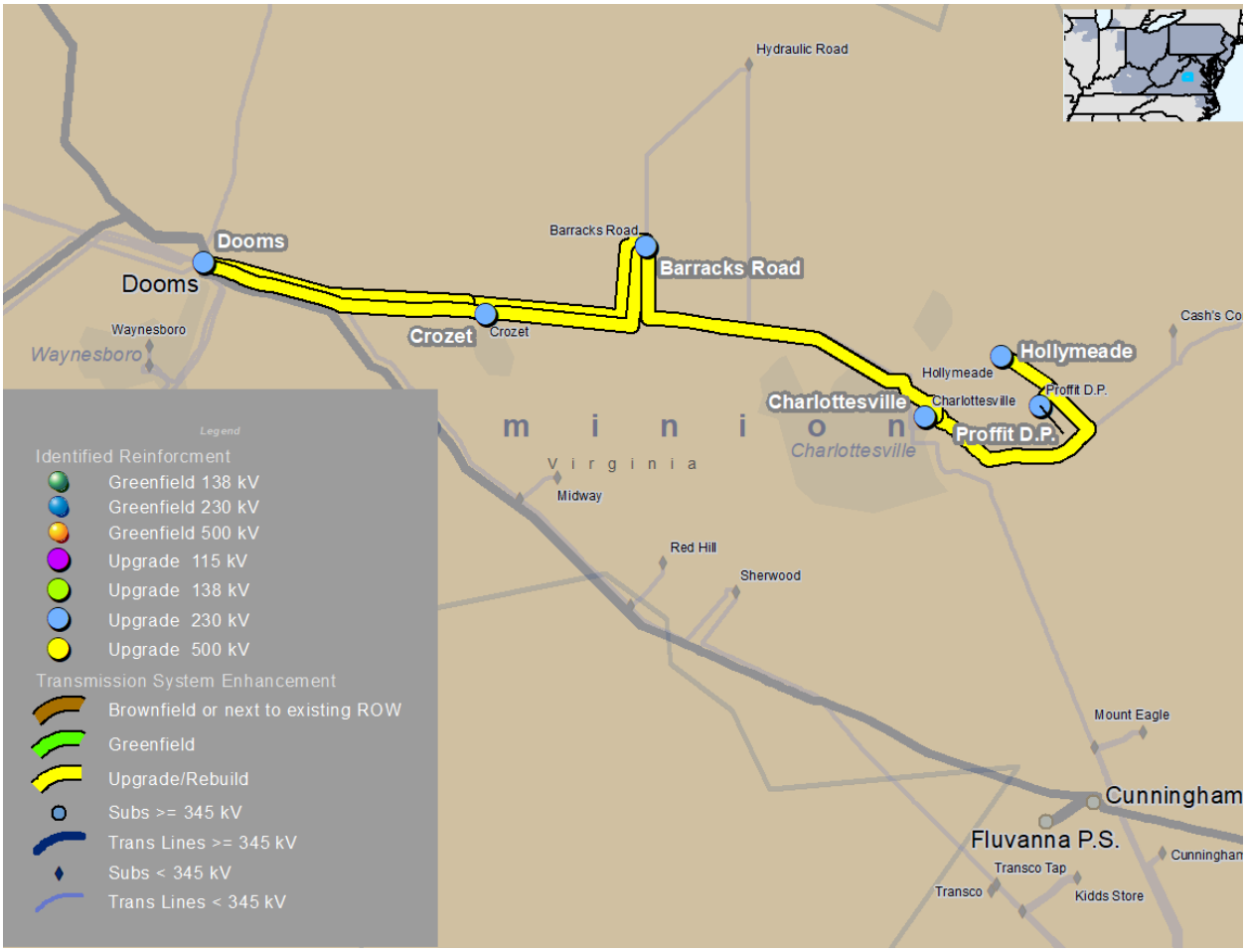


Proposal 967 includes the following 230 kV line rebuilds, along with relay resets/revisions at Hollymeade, Proffit, Barracks Road and Crozet substations:

- Line No. 2054 (Charlottesville-Proffit DP) rebuild using double circuit capable 500/230 kV poles (the 500 kV circuit will not be wired as part of this project)
- Line No. 233 (Charlottesville-Hydraulic Rd-Barracks Road-Crozet-Dooms) rebuild
- Line No. 291 (Charlottesville-Barracks Road-Crozet-Dooms) rebuild

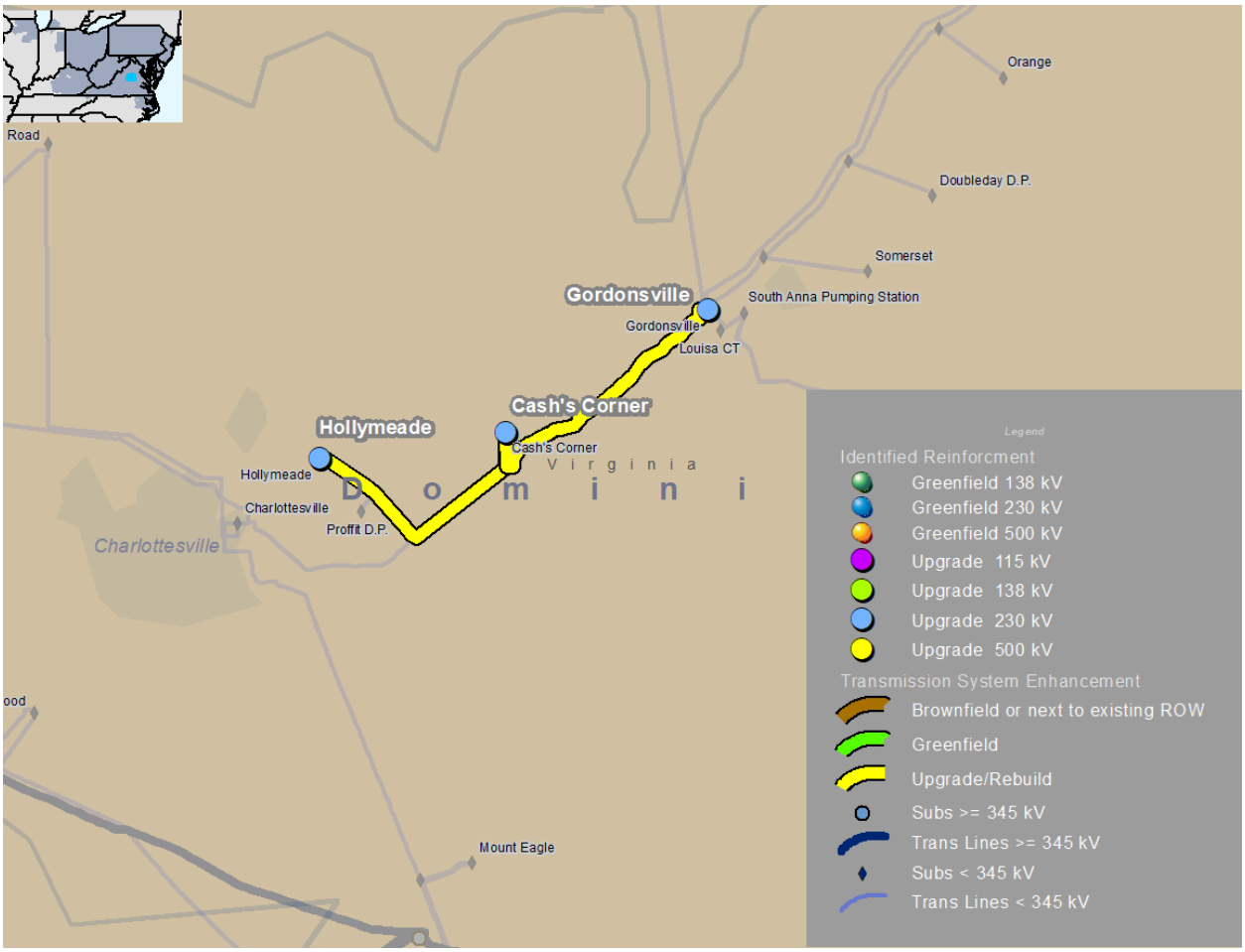
Terminal equipment upgrades will also be required at Charlottesville substation for the Line No. 2054, Line No. 233 & Line No. 291 rebuilds, Hydraulic Road for the Line No. 233 & Line No. 291 rebuilds and Dooms substation for the Line No. 233 & No. 291 rebuilds. The estimated cost is $183.49 million, and the required in-service date is June 2027 with a projected in-service date of June 2028. The local transmission owner, Dominion, will be designated to complete this work.

Map 12. South Area Improvements – Proposal 967



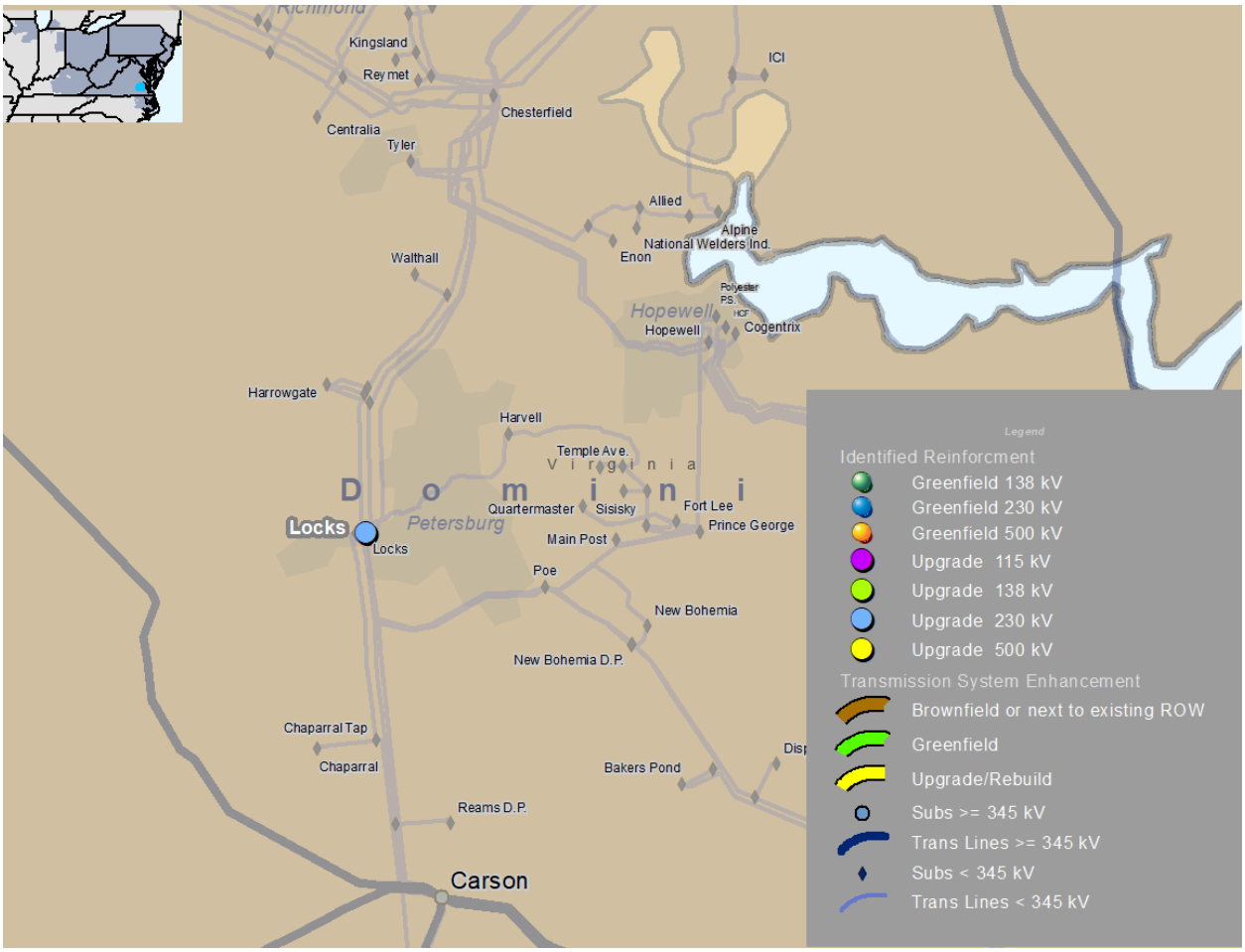
Proposal 211 includes the rebuild of line No. 2135, Hollymeade-Gordonsville 230 kV, using double circuit capable 500/230 kV poles (the 500 kV circuit will not be wired as part of this project). Terminal equipment will also be upgraded at the Hollymeade, Gordonsville and Cash's Corner 230 kV substations. The estimated cost is $54.85 million, and the required in-service date is June 2027 with a projected in-service date of June 2028. The local transmission owner, Dominion, will be designated to complete this work.

Map 13. South Area Improvements – Proposal 211



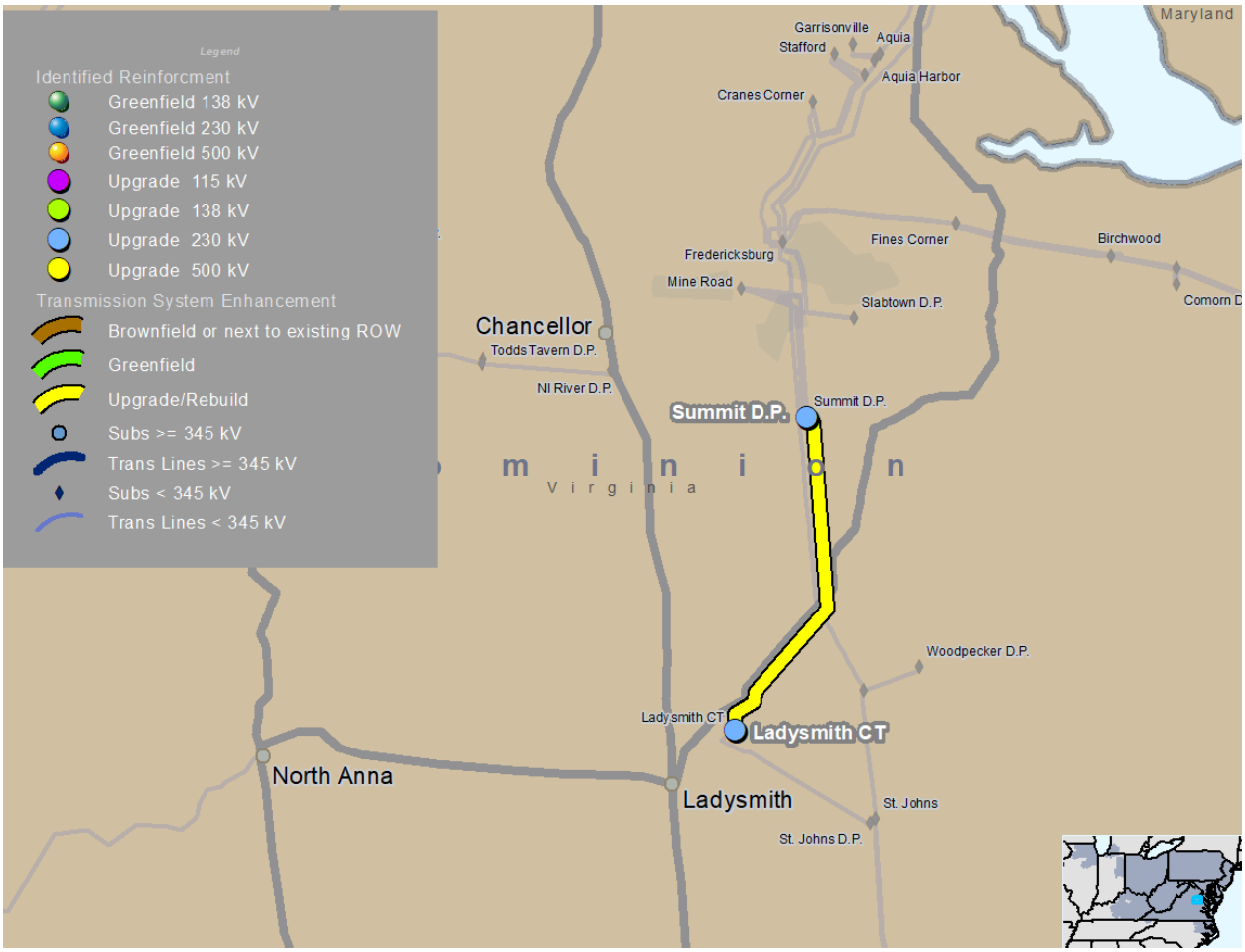
Proposal 731 replaces the single unit Locks 230/115 kV 168 MVA transformer TX No. 7 with a new single unit transformer with a rating of 224 MVA. The leads line at the 115 kV level would also be upgraded to 2000A. The estimated cost is $7.14 million, and the required in-service date is June 2027 with a projected in-service date of June 2028. The local transmission owner, Dominion, will be designated to complete this work.

Map 14. South Area Improvements – Proposal 731



The partial scope of proposal 74 includes the wreck and rebuild of line No. 2090, Ladysmith CT-Summit D.P. 230 kV segment as a double circuit 230 kV line; however, only one circuit will be wired at this stage. Circuit breaker leads, switches and line leads will be upgraded at Ladysmith CT 230 kV substation. The estimated cost is $36.50 million, and the required in-service date is June 2027 with a projected in-service date of December 2027. The local transmission owner, Dominion, will be designated to complete this work.

Map 15. South Area Improvements – Partial Scope of Proposal 74

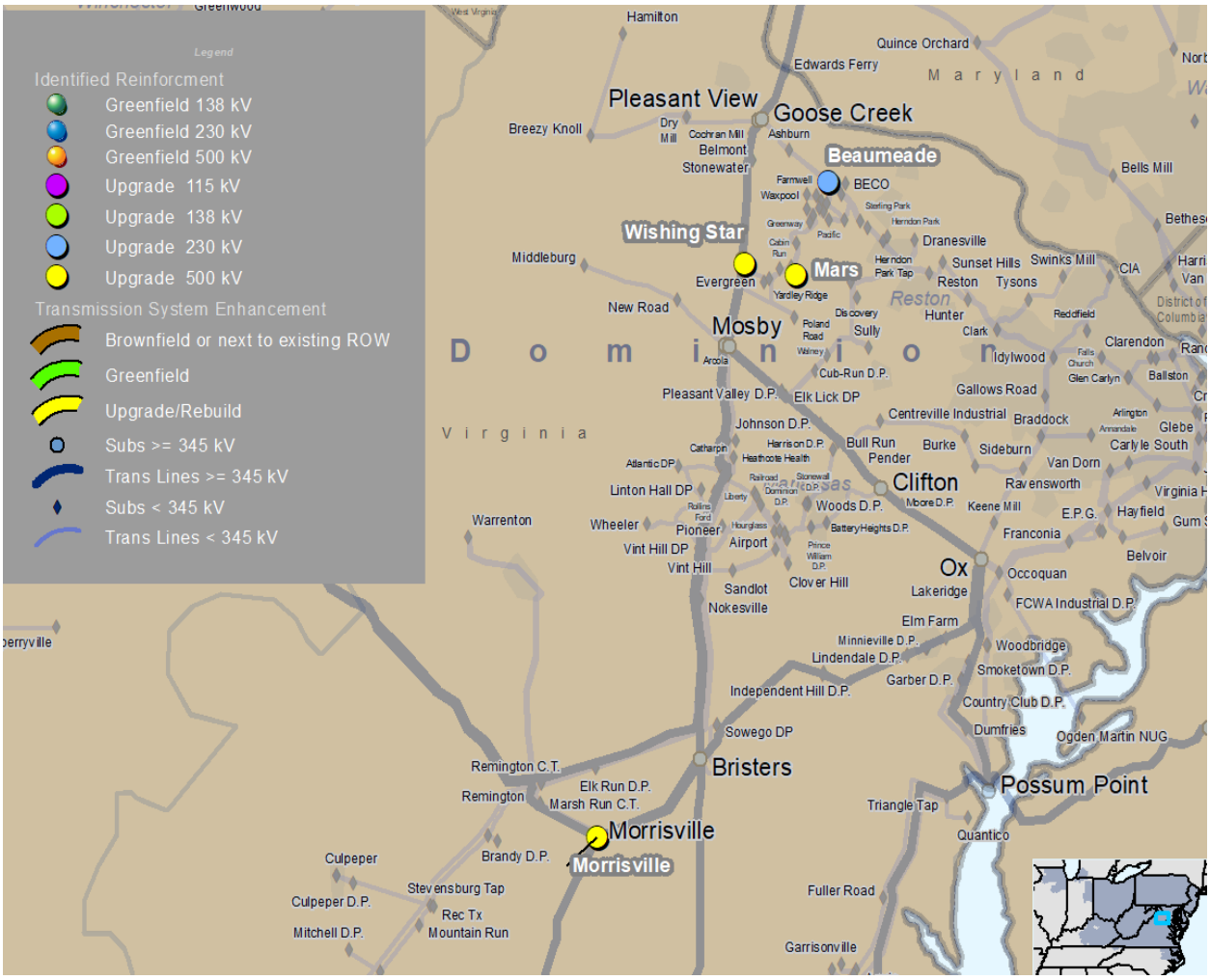


Proposal 231 entails the installation of 230 kV and 500 kV shunt cap banks (static devices) as well as STATCOMs (dynamic devices) and associated equipment to address the reactive power needs of the system. Below is the list of the devices:

- One 500 kV, 150 MVAR shunt capacitor bank and associated equipment at Morrisville substation
- One 230 kV, 150 MVAR shunt capacitor bank and one 500 kV, 293.8 MVAR shunt capacitor bank and associated equipment at Wishing Star substation
- One 500 kV, 300 MVAR static synchronous compensator (STATCOM) and one 230 kV, 150 MVAR shunt capacitor bank and associated equipment at Mars substation
- One 230 kV, 300 MVAR static synchronous compensator (STATCOM) and associated equipment at Beaumeade substation

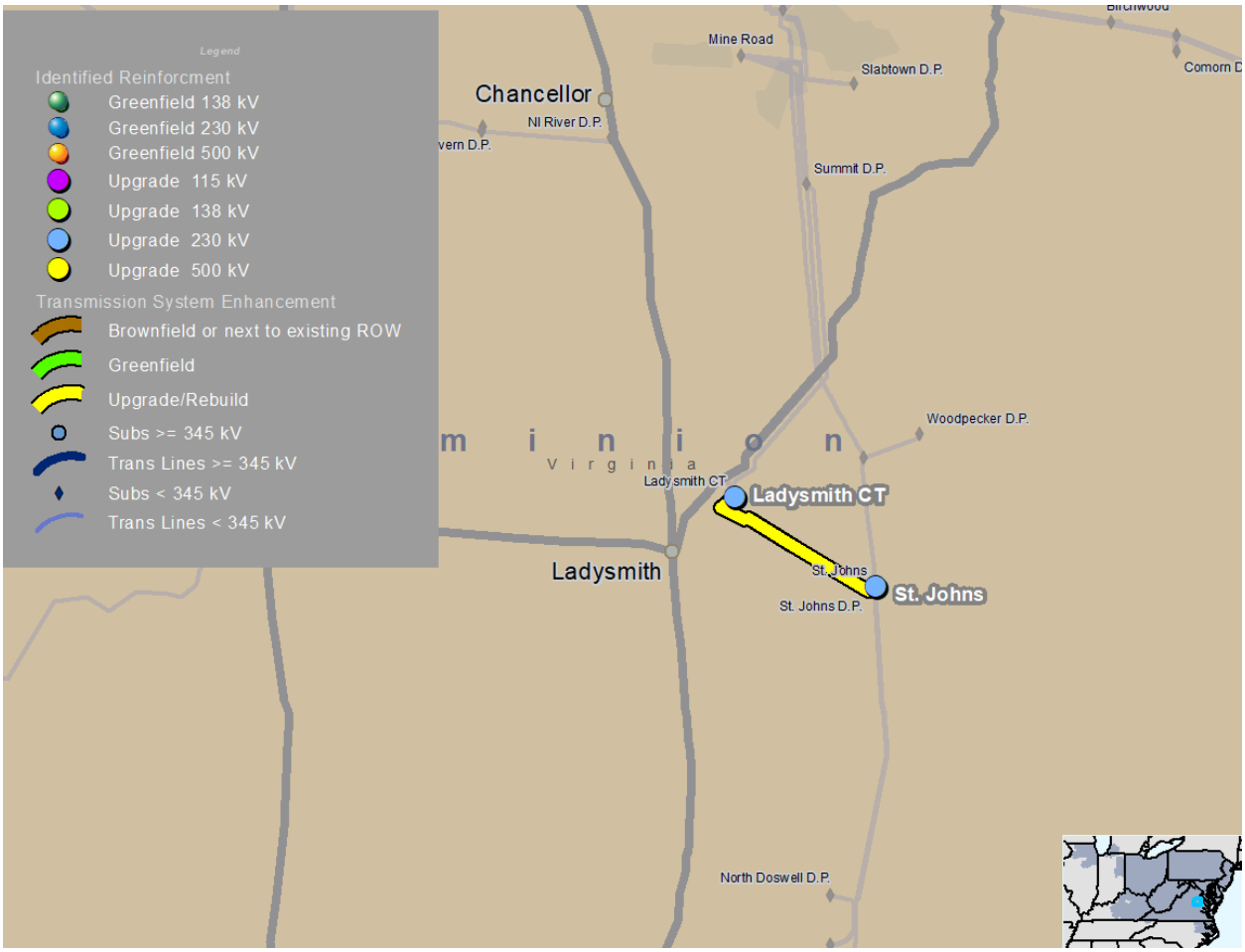
The estimated cost is $103.79 million, and the required in-service date is June 2027 with a projected in-service date of December 2027. The local transmission owner, Dominion, will be designated to complete this work.

Map 16. South Area Improvements – Proposal 231



In addition to the proposals identified above, there are a number of required upgrades identified by PJM. The recommended solution will uprate 12.44 miles of 230 kV circuit 256 from St. Johns to Ladysmith CT. Approximately 7.14 miles of the line from St. Johns substation to structure 256/108 is supported by a mix of single circuit wood and steel H-frames installed in 1991. This portion of the line will be rebuilt with a mix of light duty steel DOM pole tangent H-frames and engineered steel three-pole dead-end angle structures. The proposed conductor for the rebuilt line will be 2-768 ACSS "Maumee" with dual 48 fiber DNO-11410 for shielding. The remaining 5.3 miles of the line from structure 256/107 to Ladysmith CT is supported on double circuit lattice towers installed in 2010–2011. This portion of the line will be reconductored with proposed 2-768 ACSS "Maumee" conductor, and the existing structures and shield wire will remain. Transmission line switch 25666 will be upgraded to 4000A at St. Johns substation. Terminal equipment at remote end substations will be upgraded to 4000A continuous current rating to support new conductor ratings. The estimated cost is $37.89 million, with a required and projected in-service date is June 2028. The local transmission owner, Dominion, will be designated to complete this work.

Map 17. South Area Improvements – PJM Identified Upgrades



Overall, the total cost estimate for the recommended south area improvements is approximately $1,265.85 million.

Northern Virginia Data Center

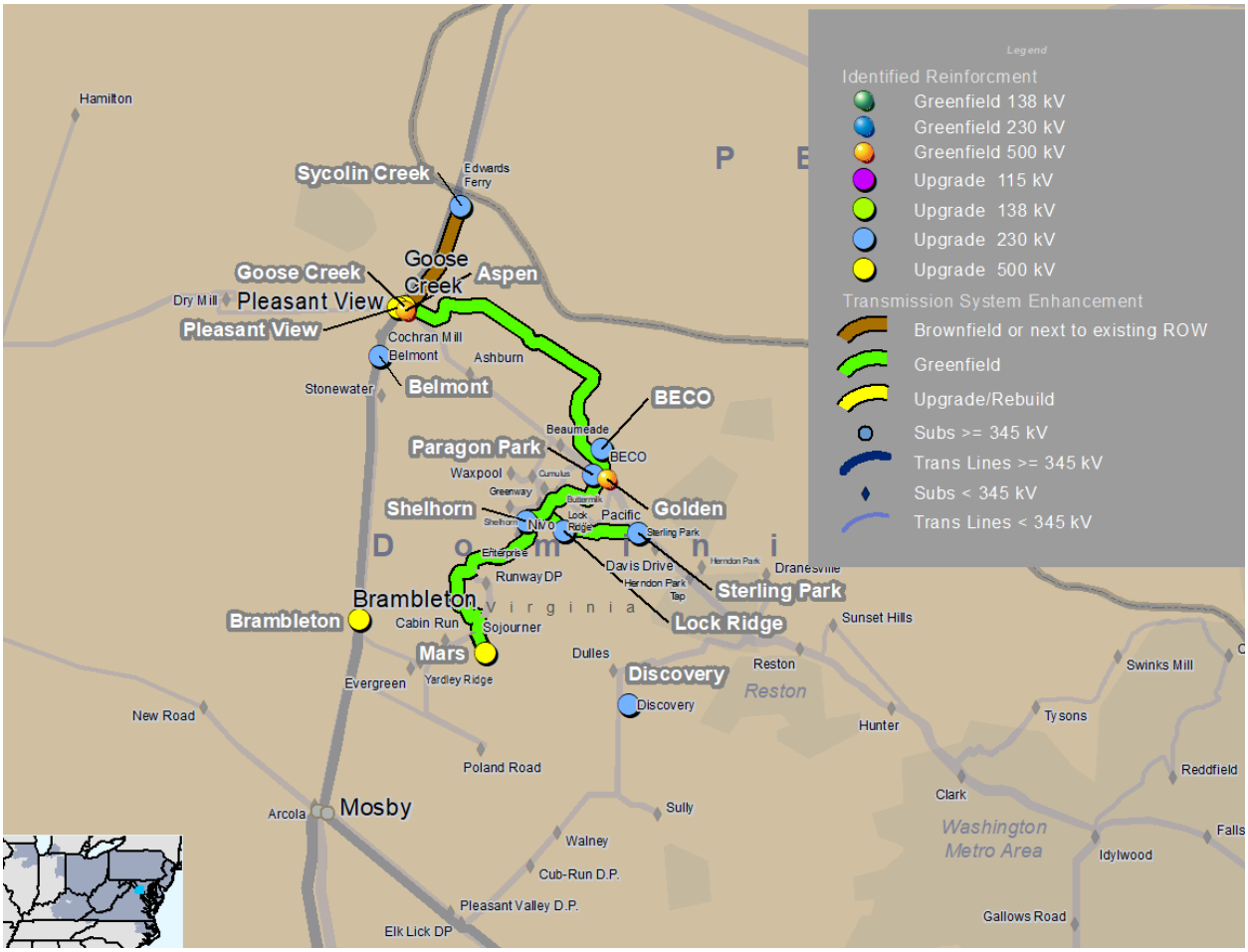
PJM recommends proposal 692 and 516 proposed by Dominion, proposal 344/660 proposed by Exelon and proposal 837 proposed by FirstEnergy to address the northern Virginia data center cluster needs. There are also a number of additional upgrades identified by PJM.

Proposal 692 includes the construction of two new 500/230 kV substations, Aspen and Golden. The Aspen substation will be tapping the 500 kV line No. 558. New double circuit 500/230 kV lines from Aspen to Golden substation will be constructed, where the 230 kV line will connect Aspen-Sycolin Creek-Golden. Similarly, the proposal also includes construction of new double circuit 500/230 kV lines from Golden to Mars, where the 230 kV line will connect Golden-Lockridge-Mars. The project will build a new Aspen-Goose Creek 500 kV line, and install a second 500/230 kV 1440 MVA transformer at the Mars substation. The existing double circuit Golden-Paragon Park 230 kV lines (lines No. 2150 and 2081) will be upgraded, along with the existing single circuit Paragon Park-BECO 230 kV line (line No. 2207). The latter 230 kV line will require a minimum normal summer rating of 1573 MVA, and equipment at each substation will be upgraded to support the new conductor rating of 4000A. The relay settings at Golden substation will be reset, and the overdutied breakers at Belmont, BECO, Beaumeade, Pleasant View, Shellhorn and Discovery will be replaced. The estimated cost is $1,025.06 million, and the required in-service date is

June 2027 with a projected in-service date of June 2028. The local transmission owner, Dominion, will be designated to complete this work.

In addition to the scope identified above, there are a couple of reconductors that will be needed. Specifically, 1.47 miles of the Sterling Park-Golden 230 kV double circuit lines (line No. 2081 and 2150), and 0.67 miles of the Davis Drive-Sterling Park 230 kV double circuit lines (lines No. 2194 and 9231) will need to be reconductored. The estimated cost is $13.5 million, and the required in-service date is June 2027 with a projected in-service date of June 2028. The local transmission owner, Dominion, will be designated to complete this work.

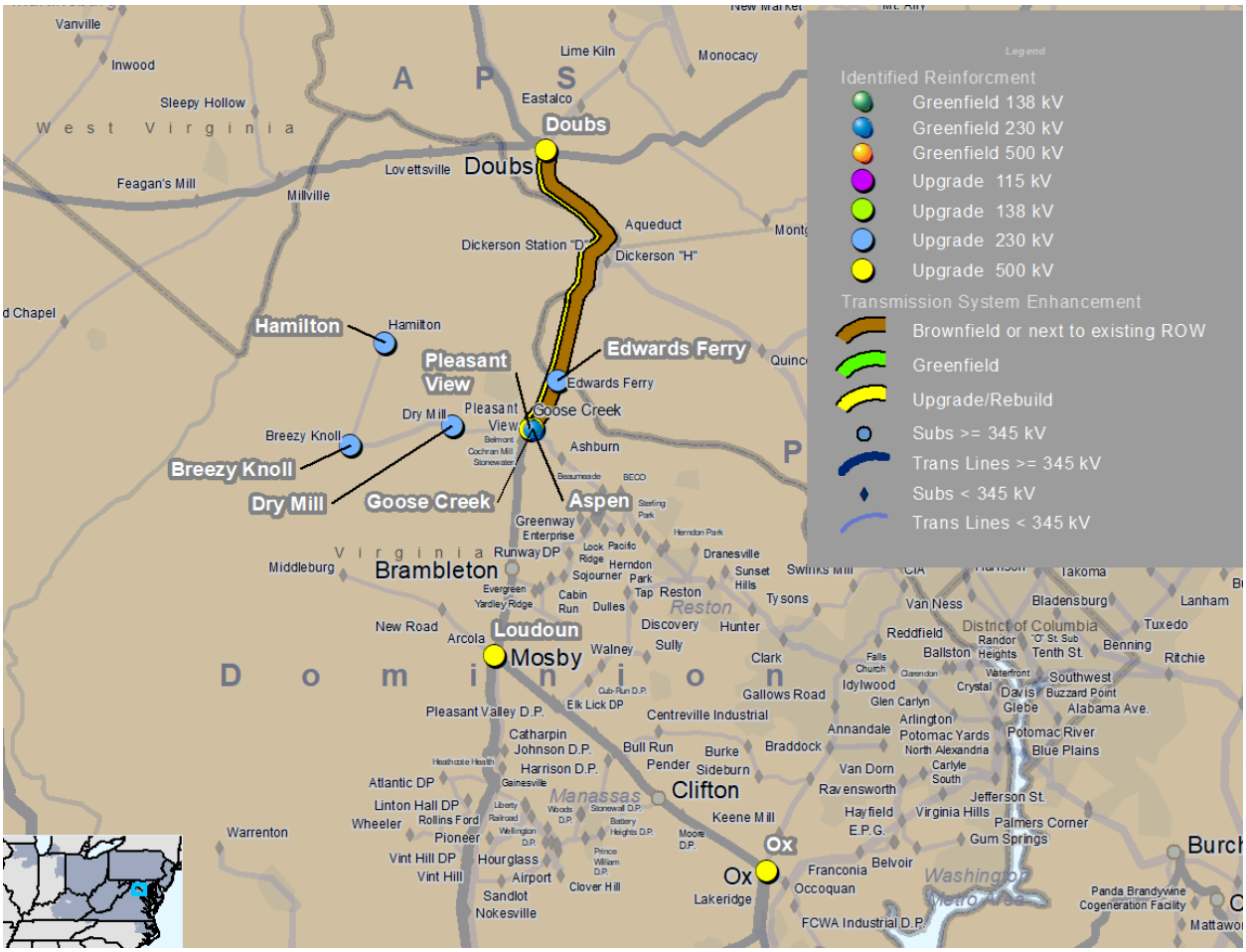
Map 18. Data Center Area Improvements – Proposal 692 and Additional Reconductors



Proposal 516 includes the rebuild of Doubs-Goose Creek 500 kV (line No. 514) using double circuit 500/230 kV towers on foundations. This scope covers line construction between Goose Creek and the Doubs Interconnection point, which is south of the Potomac River. The proposal also constructs a new 500 kV line between Doubs and the new Aspen substation, including line construction between Aspen and the Doubs Interconnection point, which is south of the Potomac River. The Pleasant View-Dickerson 230 kV line (line No. 203), from Pleasant View substation and structure 203/15 within the existing ROW, will be rebuilt using double circuit 500/230 kV towers on foundations. Approximately 1 mile of 230 kV line No. 2098 between Pleasant View and Structure 2098/9, where line No. 2098 turns toward Hamilton Substation, will be wrecked and rebuilt. The one-mile portion will share the new double circuit 500/230 kV towers with line No. 514, which is being rebuilt as part of the project. Relays will be reset or revised at Breezy, Dry Mill and Hamilton 230 kV substations. The terminal equipment at Goose Creek, Pleasant View and

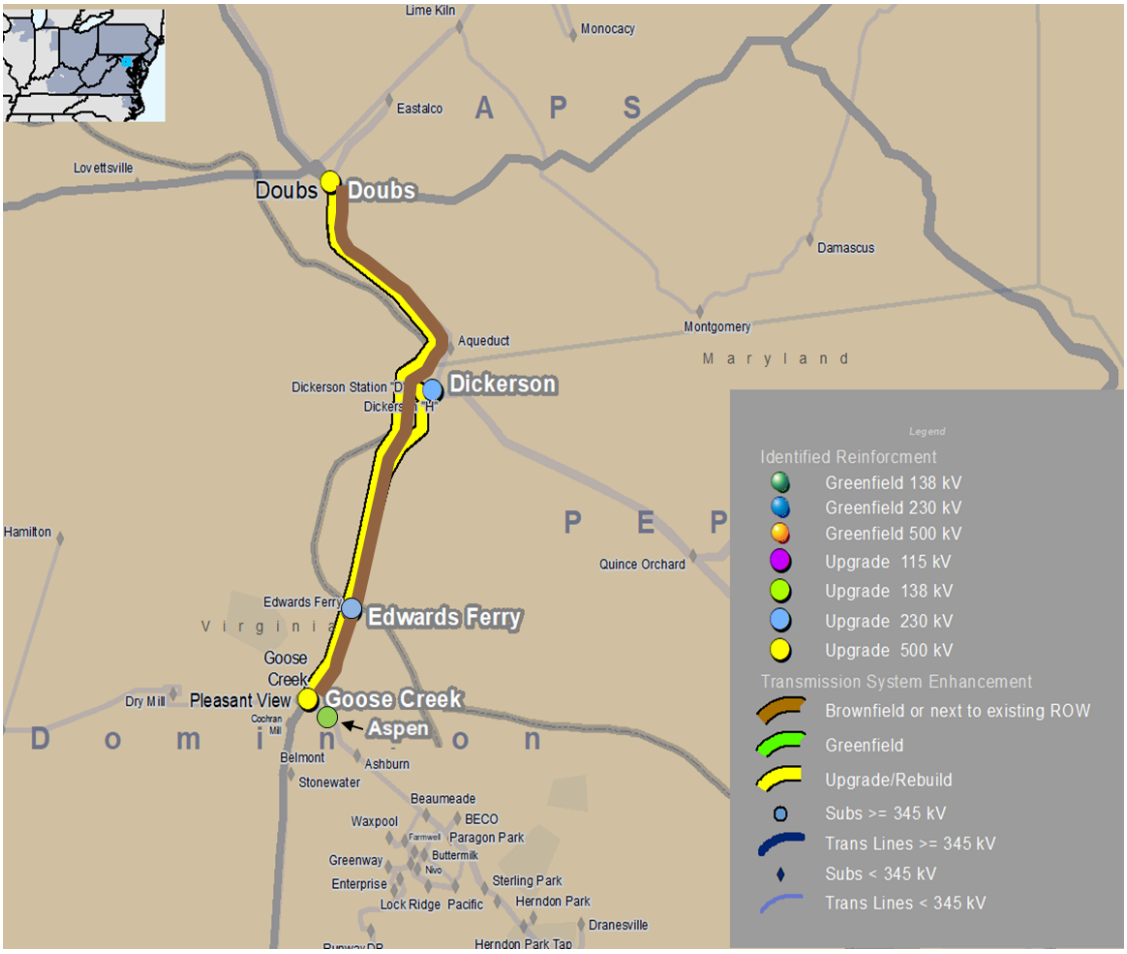
Edwards Ferry 230 kV substations will be upgraded, and overdutied breakers will be replaced at the Loudon, Ox and Pleasant View 500 kV substations. The estimated cost is $78.4 million, and the required in-service date is June 2027 with a projected in-service date of December 2027. The local transmission owner, Dominion, will be designated to complete this work.

Map 19. Data Center Area Improvements – Proposal 516


Legend
Identified Reinforcment
Greenfield 138 kV
Greenfield 230 kV
Greenfield 500 kV
Upgrade 115 kV
Upgrade 138 kV
Upgrade 230 kV
Upgrade 500 kV
Transmission System Enhancement
Brownfield or next to existing ROW
Greenfield
Upgrade/Rebuild
Subs >= 345 kV
Trans Lines >= 345 kV
Subs < 345 kV
Trans Lines < 345 kV
Doubs
Aqueduct
Dickerson Station "D"
Dickerson "H"
Hamilton
Pleasant View
Edwards Ferry
Goose Creek
Breezy Knoll
Dry Mill
Aspen
Brambleton
Loudoun
Mosby
Ashburn
Reston
Clifton
Manassas
Ox
Lakeridge
Occoquan
Franconia
Belvoir
Gum Springs
Virginia Hills
Jefferson St.
Palmers Corner
Hayfield
Keene Mill
Van Dorn
Ravensworth
Annandale
Braddock
Burke
Pender
Sideburn
Bull Run
Centreville Industrial
Gallows Road
Clark
Discovery
Hunter
Walney
Sully
Arcola
New Road
Middleburg
Warrenton
Vint Hill
Vint Hill DP
Hourglass
Airport
Sandlot
Nokesville
Clover Hill
Pioneer
Rollins Ford
Wheeler
Linton Hall DP
Atlantic DP
Harrison D.P.
Johnson D.P.
Catharpin
Pleasant Valley D.P.
Elk Lick DP
Cub Run D.P.
Dulles
Cabin Run
Tap
Sojourner
Herndon Park
Runway DP
Greenway
Enterprise
Dranesville
Sunset Hills
Tysons
Van Ness
Bladensburg
Lanham
Takoma
District of Columbia
Reddfield
Ballston
Tenth St.
Benning
Ritchie
Southwest
Buzzard Point
Alabama Ave.
Potomac River
Blue Plains
Arlington
Potomac Yards
North Alexandria
Carlyle South
Glebe
Crystal
Idylwood
Glen Carlyn
Falls Church
Randor Heights
O St Sub
Tuxedo
Waterfront
Clarendon
Fairfax
Chantilly
Centreville
Manassas Park
Haymarket
Gainesville
Linton Hall
Bristow
Nokesville
Catlett
Remington
Culpeper
Fauquier
Loudoun
Prince William
Stafford
Spotsylvania
Orange
Fredericksburg
Caroline
Hanover
Louisa
Goochland
Fluvanna
Albemarle
Charlottesville
Greene
Madison
Rappahannock
Culpeper
Orange
Spotsylvania
Stafford
Fredericksburg
Caroline
Hanover
Louisa
Goochland
Fluvanna
Albemarle
Charlottesville
Greene
Madison
Rappahannock
Fauquier
Loudoun
Prince William
Stafford
Spotsylvania
Orange
Fredericksburg
Caroline
Hanover
Louisa
Goochland
Fluvanna
Albemarle
Charlottesville
Greene
Madison
Rappahannock
Culpeper

equipment including disconnect switches, CTs and substation conductor, and relaying will be replaced at the Doubs 500 kV substation. The estimated cost is $234.96 million, and the required in-service date is June 2027 with a projected in-service date of June 2030. The local transmission owner, FirstEnergy, will be designated to complete this work.

Map 20. Data Center Area Improvements – Proposals 344/660 and 837



Overall, the total cost estimate for the recommended northern Virginia data center area improvements is approximately $1,418.3 million.

East

PJM recommends proposal 344/660 by Exelon, proposal 374 by PPL, proposal 637 by PSEG and proposal 837 by FirstEnergy to address the East cluster needs.

PJM is sought to utilize and incorporate already Board-approved NJ SAA project scope at North Delta substation, and adjusted the Exelon proposal 344/660 scope accordingly. The recommended solution expands the North Delta 500 kV substation (scope beyond that proposed under Brandon Shore deactivation) to accommodate the termination of the new 500 kV lines as well as reconfiguration of the Peach Bottom substation. The North Delta 500 kV substation expansion will include a four bay breaker and a half configuration. The proposal includes building a High Ridge 500 kV substation, which will cut into the Brighton-Waugh Chapel 500 kV line. The High Ridge 500 kV substation will include

three bay breaker and a half configuration with two 500/230 kV transformers, and terminal equipment will require replacement at both Brighton and Waugh Chapel 500 kV substations.

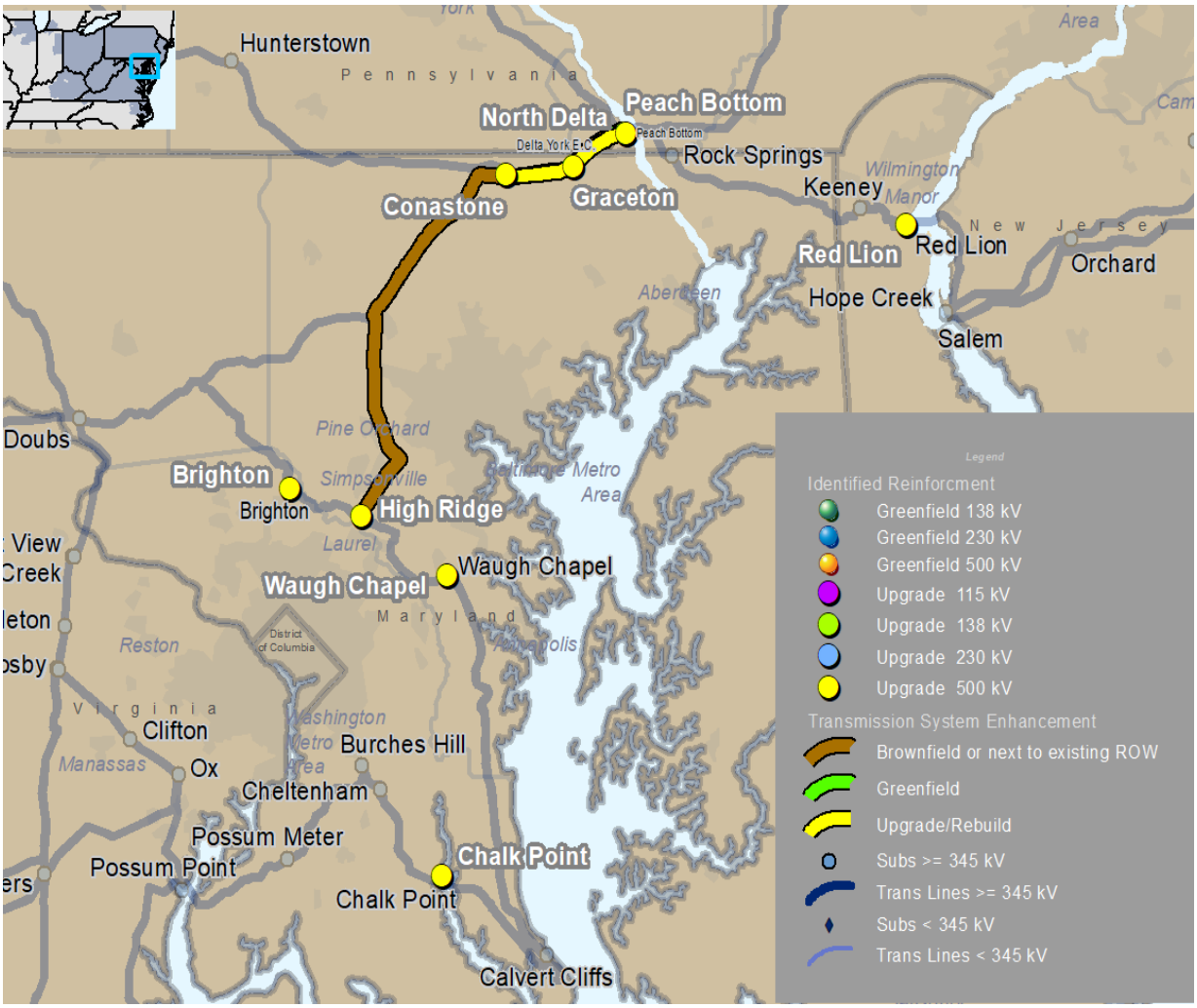
The proposal builds a new Peach Bottom South-North Delta 500 kV line by cutting into Peach Bottom tie No. 1 and extending the line to North Delta, which entails approximately 1.25 miles new ROW. The existing Peach Bottom-Conastone 500 kV line (5012L) will be rebuilt on single circuit structures within existing ROW and cut into North Delta 500 kV and Gracetone 500 kV stations. Furthermore, the proposal builds a new North Delta-High Ridge 500 kV line, which will extend approximately 65 miles.

In addition to the regional proposal scope described above, there following Exelon proposal components would be required:

- Conastone-Brighton 500 kV (5011 circuit) – Replace terminal equipment limitations at both Conastone and Brighton 500 kV
- Brighton-Waugh Chapel 500 kV (5053) – Replace terminal equipment limitations at Brighton 500 kV
- Chalk Point-Cheltanham 500 kV (5073) – Replace relay at Chalk Point 500 kV
- Conastone-Peach Bottom 500 kV (5012 circuit) – Upgrade two existing 500 kV breakers at Conastone from 4000A to 5000A
- Peach Bottom 500 kV – Reconfigure and upgrade several terminal/substation equipment at both North and South Peach Bottom 500 kV substations
- Red Lion-Hope Creek 500 kV – Replace terminal equipment at Red Lion

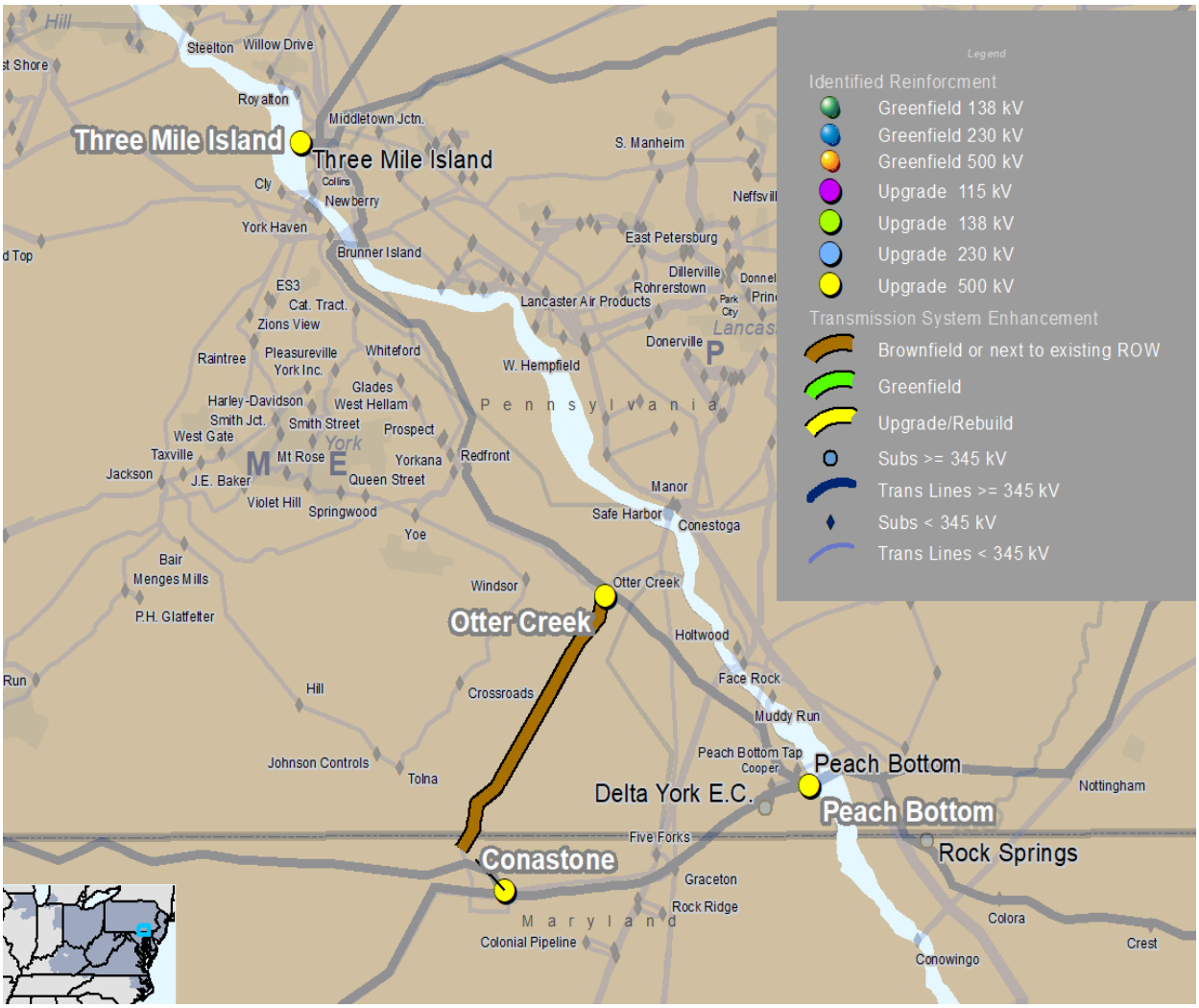
The estimated cost for the work described above is $708.77 million, and the required in-service date is June 2027 with a projected in-service date between 2028 and 2030. The local transmission owners, Exelon, will be designated to complete this work.

Map 21. East Area Improvements – Proposal 344/660



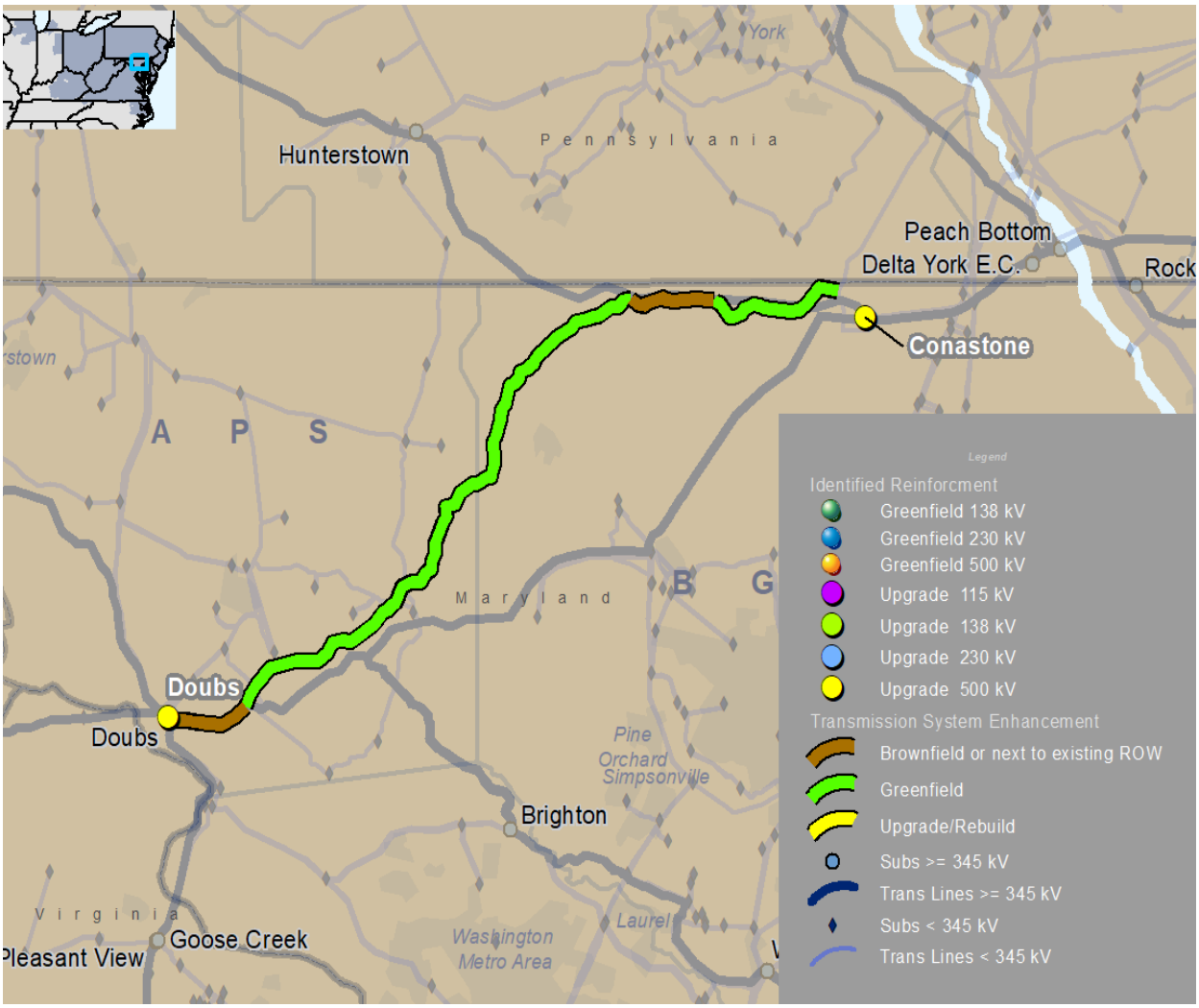
Proposal 374 by PPL includes building a new Otter Creek 500 kV switching station, with two bay three-breaker configuration, that cuts into the Peach Bottom-TMI 500 kV line. An approximately 17-mile new 500 kV line from Otter Creek toward the Conastone station fence (Conastone demarcation point) would be built, and the existing Otter Creek-Conastone 230 kV line would be rebuild to become a double circuit 500 and 230 kV line. Additionally, terminal equipment will be upgraded at the Peach Bottom and TMI 500 kV substations. The estimated cost is $134.2 million, with a required and projected in-service date of June 2027. The local transmission owners, PPL and BGE, will be designated to complete this work.

Map 22. East Area Improvements – Proposal 374



Proposal 637 by PSEG includes an approximately 40-mile new 500 kV line from the Conastone demarcation point (with the PPL Otter Creek line) to Doubs substation. The Conastone substation is referenced for this demarcation point only for general reference and does not have to necessarily be in the area of the Conastone substation. The new 500 kV line will tie into the PPL-proposed Otter Creek-Conastone 500 kV, bypassing the actual Conastone substation. The Doubs 500 kV substation will be reconfigured and terminal equipment upgraded to terminate the new line. The estimated cost is $447.5 million, with a required and projected in-service date of June 2027. The proposing entity, PSEG, will be designated to complete this work.

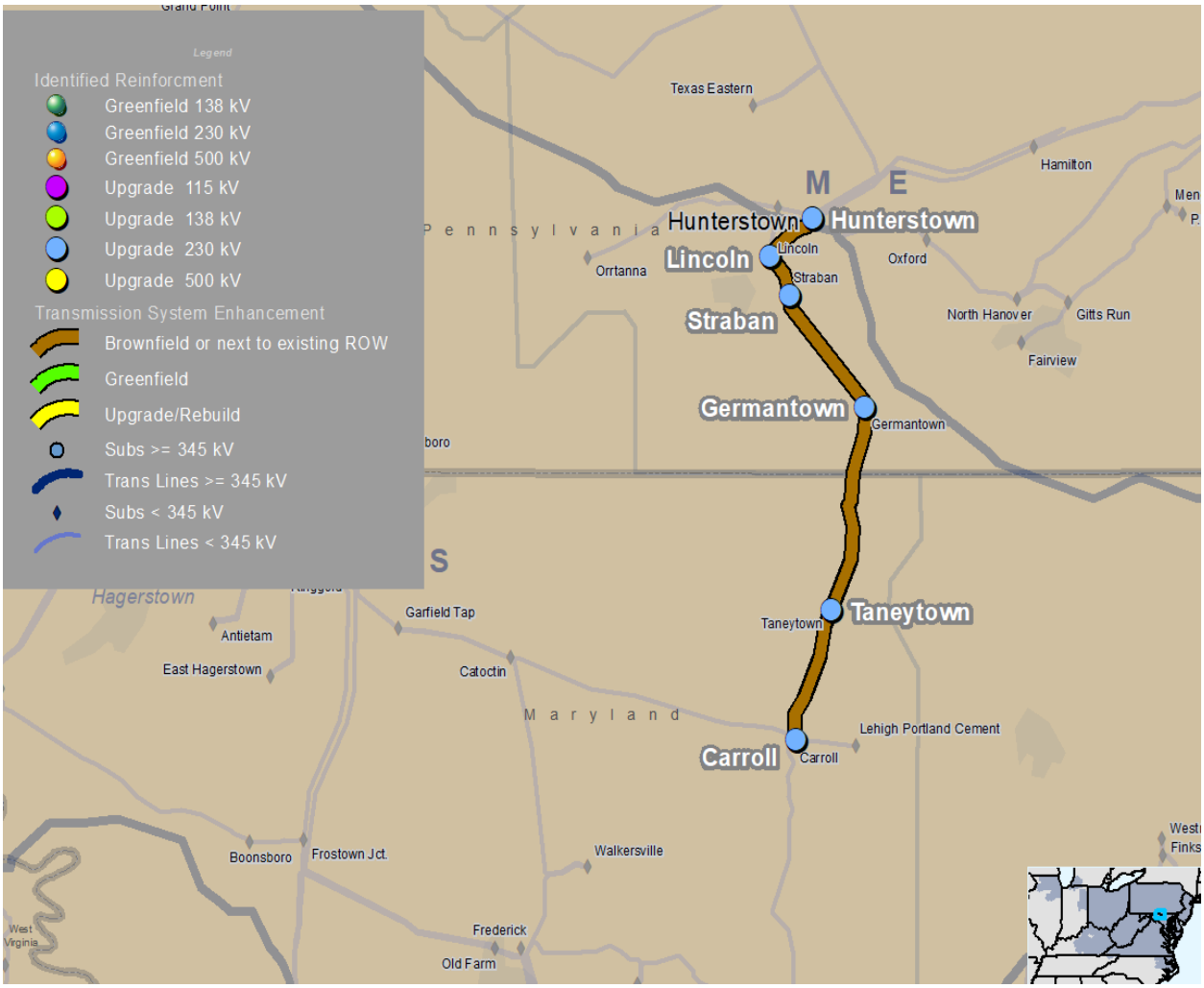
Map 23. East Area Improvements – Proposal 637



Proposal 837 by FirstEnergy builds a new Hunterstown-Carroll 230 kV line in addition to rebuilding the existing 115/138 kV corridor as double circuit using 230 kV construction standards.

In addition to the Hunterstown-Carroll 230 kV line scope, there are a few PJM identified upgrades that will be needed. Specifically, the Lincoln-Orrtanna 115 kV line will be reconductored, and the line trap at the Grand Point 138 kV substation for the Fayetteville-Grand Point 138 kV line will be replaced. The proposal also includes the replacement of the line trap, substation conductor, breaker, relaying and CTs at Ringgold 138 kV substation for the Reid-Ringgold 138 kV line. Furthermore, with this additional scope, the baseline project b3768, which rebuilds/reconductors the Germantown-Lincoln 115 kV line ($17.36 million) is not required and the baseline project would be canceled. The total estimated cost of the proposal 837 scope of work and the additional PJM identified upgrades is $152.65 million, and the required in-service date is June 2027 with a projected in-service date between 2028 and 2030. The local transmission owner, FirstEnergy, will be designated to complete this work.

Map 24. East Area Improvements – Proposal 837



Overall, the total cost estimate for the recommended East area improvements is approximately $1,443.12 million.

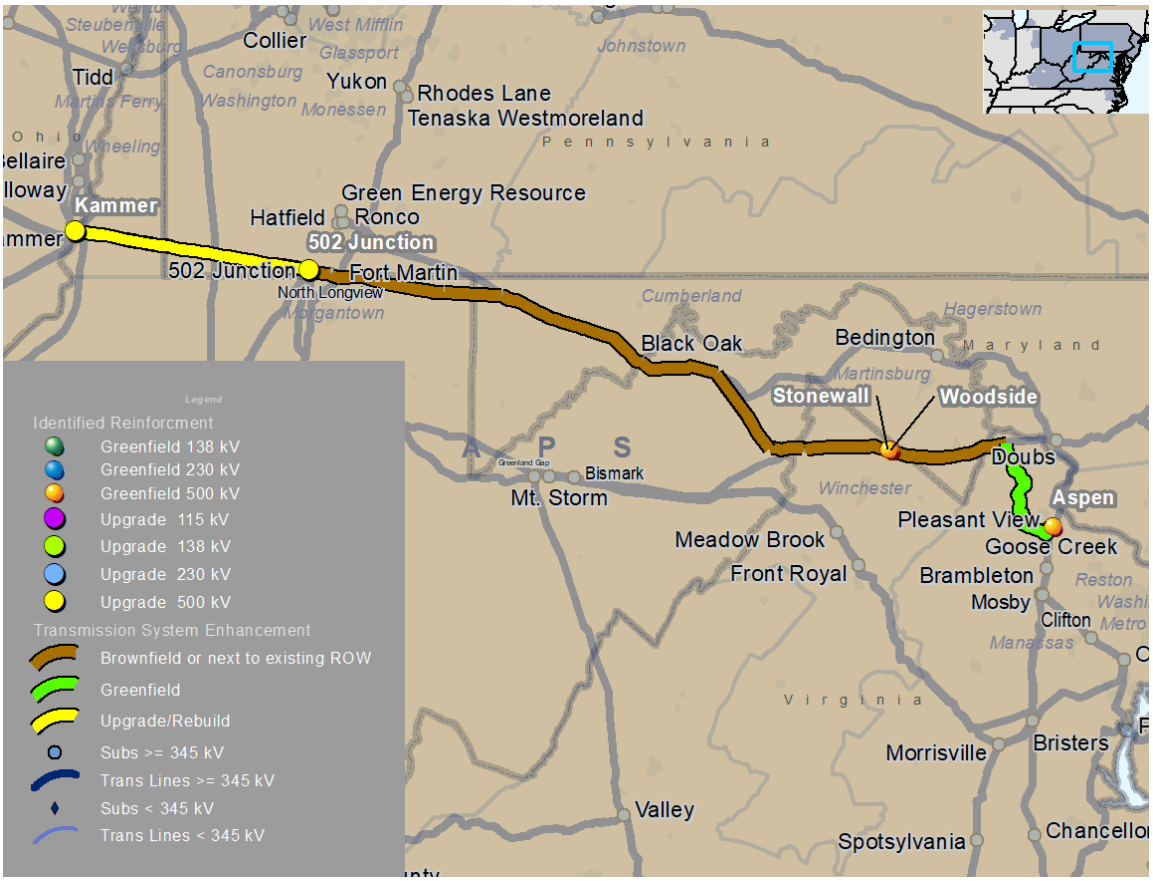
West

PJM recommends a modified scope of proposal 853 proposed by NextEra to address the West cluster needs. The recommended scope includes a new 500 kV line from the existing 502 Junction substation to a Woodside 500 kV substation, noting that the line will bypass the Black Oak substation. The existing First Energy substation, primarily 502 Jct 500 kV and Stonewall 138 kV will be upgraded by adding additional bay position via new breakers. The Woodside 500 kV substation will be a breaker and half configuration built adjacent to the existing Stonewall 138 kV substation, and loop in the Bismark-Doubs 500 kV line. The substation will include two 500/138 kV transformers, and two 150 MVAR capacitor banks as well as one +500/-300 MVAR STATCOM. Furthermore, the project will also build a new 500 kV line from the Woodside substation to the new Aspen substation (part of Northern Virginia Data Center cluster recommended solution). Aspen substation work will be required to terminate the Woodside-Aspen 500 kV line. The 500 kV line to be built east and west of existing Stonewall 138 kV will be assigned to First Energy's on existing ROW with 500 kV overbuilt. First Energy will be assigned roughly 36 miles of the 500 kV overbuilt.

The recommended solution also includes a LIDAR sag study to assess the summer emergency rating and any needed upgrades on the Kammer-502 Junction 500 kV line to adequately increase the line rating.

The estimated cost of work assigned to FE is $392.55 million. The estimated cost of work assigned to NextEra is $512.61 million and the estimated cost of work assigned to Dominion is $35.59 million. The estimated cost of work assigned to AEP is $0.1 million. The required in-service date is June 2027 with a projected in-service date between 2027 and 2030. The proposing entity, NextEra, along with the local transmission owners, FirstEnergy, Dominion and AEP, will be designated to complete this work. Overall, the total cost estimate for the recommended West area improvements is approximately $940.85 million.

Map 25. West Area Improvements – Modified Proposal 853



Short Circuit

Stemming from PJM's short-circuit analysis, PJM recommends the replacement of 36 circuit breakers, as detailed in the Short-Circuit Analysis section of this report. The total cost estimate to for the breaker replacements is approximately $63.27 million.

Table 10. Rationale – All Clusters

#	Proposal ID	Proposing Entity	Focus Area (s)	Project Title	Submitted Cost ($M)	Meet Reliability Needs In: 2027 Model	Meet Reliability Needs In: 2028 Model	Selected Y/N	Rationale	Applicable Scenarios	
1	9	**AEP**	Local AEP	Scottsville-Bremo Sag Study	$1.27	**Yes**	**Yes**	No	Not required to meet the 2022W3 needs with the selected PJM 500 kV solutions (that address the primary need drivers for the window)	N/A	
2	23	**POTOED – FirstEnergy**	West	Data Center Reinforcement Proposal No. 2 • 2 - 500 kV circuits from Fort Martin-Doubs • 1 - 500 kV circuit from Prutnytown-Meadow Brook-Doubs • Second 500 kV from Doubs-Aspen and Rebuild the existing Doubs-Goose Creek 500 kV • Rebuild Hunterstown-Caroll 115/138 kV line for 230 kV double circuit construction	$3,503.86	**Yes**	**No**	Yes *(partial)*	• Proposal attempts to address the west-east transfer needs and voltage collapse concerns along the transfer path • PJM analysis indicated that the system reliability benefits more from spreading the reinforcements for transfer between the East and West corridors instead of just the Western corridor • All options provide injections into Doubs; however, no solutions offered to debottleneck the Doubs-Goose Creek corridor • Currently there is no need for 2x500 kV double circuit development along the West-East corridor • Only 1x500 kV is required part of the PJM selected solution • Cost is higher than similar 500 kV proposals by other entities that provide stronger cost containment provisions • Proposal utilizes existing ROWs for parts of the projects including the new Doubs-Aspen 500 kV and Huntertown-Caroll 230 kV, which both components are in the list of PJM selected projects	• 0F • 0G • 0H / 0H2 • 0I • 0J / 0J-2 / 0J-3 • 0K • 0M	• 0N • 0O3 • 0P / 0P2 / 0P NGME • 0Q / 0Q2 / 0Q3 / 0Q4 • 0R / 0R2 • 0S
3	24	**PSEG**	EAST	Proposal A - North Delta-New Raphael-Waugh Chapel 500 kV	$739.40	**Yes**	**Yes**	No	Selected proposal meets needed system performance with less impact (Green Field vs Brownfield and Timeline/construction risk considerations)	OS-REV	

#	Proposal ID	Proposing Entity	Focus Area (s)	Project Title	Submitted Cost ($M)	Meet Reliability Needs In: 2027 Model	Meet Reliability Needs In: 2028 Model	Selected Y/N	Rationale	Applicable Scenarios
4	28	**NextEra**	East/ West/ Northern Virginia	Hunterstown-Doubs-Goose Creek, Black Oak-Pike-Goose Creek, Pike SVC + Cap Banks	$884.05	**Yes**	**No**	No	The proposed 500 kV line is similar in length to the PJM selected 500 kV line from Otter Creek to Doubs, which is more effective in meeting the reliability need	0H/0H2
5	30	**Dominion**	South	Charlottesville-Hollymead Line No. 2054 Rebuild	$159.87	**Yes**	**Yes**	No	Dominion proposal No. 967 chosen over proposal No. 30. Both proposals include a wreck and rebuild of 230 kV Line No. 2054. However, proposal No. 30 utilizes double-circuit capable 230 kV poles, whereas proposal No. 967 utilizes double-circuit capable 500/230 kV poles.	0E11-7-B / 0E11-7-B + Yeat / 0E11-7-B +IEC West / 0E11-7-B + Hunterstown - Carrol Rebuild / 0E11-7-B + Hunterstown - Carrol Rebuild + IEC West • 0G • 0H / 0H2 • 0I • 0J / 0J-2 / 0J-3 • 0K • 0L • 0M • 0N • 0O / 0O2 / 0O3 • 0P / 0P2 / 0P NGME • 0Q / 0Q2 / 0Q3 / 0Q4 • 0R / 0R2 • 0S
6	55	**AEP**	Local AEP	Boxwood-Scottsville 138 kV Rebuild	$104.88	**Yes**	**Yes**	No	Not required to meet the 2022W3 needs with the selected PJM 500kV solutions (that address the primary need drivers for the window)	N/A
7	74	**Dominion**	South	Line No. 2090 (Ladysmith CT-Fredericksburg) Rebuild	$57.34	**Yes**	**Yes**	Yes *(partial)*	Required for reliability needs. Most efficient or cost-effective solution	0E11-7-B / 0E11-7-B + Yeat / 0E11-7-B +IEC West / 0E11-7-B + Hunterstown - Carrol Rebuild / 0E11-7-B + Hunterstown - Carrol Rebuild + IEC West / 0E11-7-B Final • 0G • 0H / 0H2 • 0I • 0J / 0J-2 / 0J-3 • 0K • 0L • 0M • 0N • 0O / 0O2 / 0O3 • 0P / 0P2 / 0P NGME • 0Q / 0Q2 / 0Q3 / 0Q4 • 0R / 0R2 • 0S

#	Proposal ID	Proposing Entity	Focus Area (s)	Project Title	Submitted Cost ($M)	Meet Reliability Needs In: 2027 Model	Meet Reliability Needs In: 2028 Model	Selected Y/N	Rationale	Applicable Scenarios
8	116	**NextEra**	East/ Northern Virginia	Hunterstown-Doubs-Gant Solution, two new 230 kV line from new Belmont to Farmwell and Roundtable substation to feed data center alley	$478.87	**Yes**	**No**	No	The proposed 500 kV line is similar in length to the PJM selected 500 kV line from Otter Creek to Doubs, which is more effective in meeting the reliability need	0H/0H2
9	125	**PSEG**	EAST	Proposal B - North Delta-Northeast 230 kV	$313.34	**Yes**	**No**	No	Not required to meet the 2022W3 needs (inferior to selected solutions) with the selected PJM 500 kV solutions (that address the primary need drivers for the window)	N/A
10	129	**Dominion**	Northern Virginia/ South	Dominion Aggregate 500 kV Proposal	$3,035.05	**Yes**	**Yes**	Yes *(Partial)*	Offers robust solution to serve the data center loads in the Dominion zone (northern Virginia) and also offers parallel 500 kV path to the single 500 kV line between Goose Creek and Wishing Star	• 1A / 1B / 1C / 1C-1 • 0E Series • 0F • 0G • 0H / 0H2 • 0I • 0J / 0J-2 / 0J-3 • 0K • 0L • 0M • 0N • 0O / 0O2 / 0O3 • 0P / 0P2 / 0P NGME • 0Q / 0Q2 / 0Q3 / 0Q4 • 0R / 0R2 • 0S
11	175	**NextEra**	ALL	Combination of PEBO 215A + WOP 1F + SOP 8E	$6,265.95	**Yes**	**Yes**	No	• Solution (as one package) is more expensive, less effective and less efficient than selected proposal. • The combination solutions fails the load deliverability test in BGE and SW-MAAC • The combination proposal, particularly in the Eastern cluster introduces significant additional number of 230 kV circuits, while this elected proposal addresses those needs via 2x500 kV circuits predominantly along existing ROWs	• 0B / 0B2 / 0B3 • 0O / 0O2 / 0O3 • 0R / 0R2
12	181	**AEP**	Local AEP	Boxwood-Scottsville 138 kV Sag Study	$4.26	**Yes**	**Yes**	No	Not required to meet the 2022W3 needs with the selected PJM 500 kV solutions (that address the primary need drivers for the window)	N/A

#	Proposal ID	Proposing Entity	Focus Area (s)	Project Title	Submitted Cost ($M)	Meet Reliability Needs In: 2027 Model	Meet Reliability Needs In: 2028 Model	Selected Y/N	Rationale	Applicable Scenarios
13	196	**AEP**	Local AEP	Glen Lyn-Peters Mountain Rebuild	$21.89	**Yes**	**Yes**	No	Not required to meet the 2022W3 needs with the selected PJM 500 kV solutions (that address the primary need drivers for the window)	N/A
14	202	**AEP**	Local AEP	Cloverdale Transformer Addition	$57.29	**Yes**	**Yes**	No	Much higher cost comparing to Proposal 410	N/A
15	211	**Dominion**	South	Hollymead-Gordonsville Line No. 2135 Rebuild	$54.85	**Yes**	**Yes**	Yes	Required for reliability needs. Considers future load growth in Culpeper and Louisa area by supporting 500 kV developments with double-circuit capable 500/230 kV poles.	• 0E11-7-B Final • 0G • 0H / 0H2 • 0I • 0J / 0J-2 / 0J-3 • 0K • 0L • 0M • 0N • 0O / 0O2 / 0O3 • 0P / 0P2 / 0P NGME • 0Q / 0Q2 / 0Q3 / 0Q4 • 0R / 0R2 • 0S
16	217	**NextEra**	East	North Delta-Conastone Solution	$155.99	**Yes**	**Yes**	No	Solution offered part of an alternate more efficient and cost-effective proposal while utilizing existing ROW and with limited impacts	• 2 / 2A / 2B / 2C / 2D / 2E / 2F • QT1 / QT3
17	229	**PSEG**	East	Proposal C - Hunterstown-New Green Valley 500 kV	$529.11	**Yes**	**No**	No	Hunterstown supply into the northern Virginia system is inferior to supplying the northern Virginian system from the Peach Bottom area	0E2
18	231	**Dominion**	Northern Virginia/ South	Reactive Power VAR Reinforcements	$155.82	**Yes**	**Yes**	Yes *(partial)*	Required for reliability needs. Most efficient or cost-effective solution	0E11-7 / 0E11-7-A / 0E11-7-B / 0E11-7-B + Yeat / 0E11-7-B +IEC West / 0E11-7-B + Hunterstown -Carrol Rebuild / 0E11-7-B + Hunterstown -Carrol Rebuild + IEC West / 0E11-7-B Final / 0E11-8 / 0E11-9 / 0E11-10 / 0E11-10-A / 0E11-11 / 0E11-12
19	234	**AEP**	Local AEP	Glen Lyn-Peters Mountain Sag Study	$0.80	**Yes**	**Yes**	No	Not required to meet the 2022W3 needs with the selected PJM 500 kV solutions (that address the primary need drivers for the window)	N/A
20	255	**NextEra**	East/ Northern Virginia	Hunterstown-Doubs-Gant Solution	$411.61	**Yes**	**No**	No	The proposed 500 kV line is similar in length to the PJM selected 500 kV line from Otter Creek to Doubs, which is more effective in meeting the reliability need	0H/0H2

#	Proposal ID	Proposing Entity	Focus Area (s)	Project Title	Submitted Cost ($M)	Meet Reliability Needs In: 2027 Model	Meet Reliability Needs In: 2028 Model	Selected Y/N	Rationale	Applicable Scenarios
21	279	**NextEra**	West/ Northern Virginia	Black Oak-Woodside-Goose Creek, Woodside SVC + Cap Banks Solution	$429.18	**Yes**	**No**	No	Does not provide the needed supply source into the Dominion northern Virginia transmission system (Load Centers)	0E11-12
22	325	**PSEG**	East/ South	Proposal E - Brambleton-Hinsons Ford Rd 500 kV, North Delta-New Raphael Road-Waugh Chapel 500 KV	$944.05	**Yes**	**No**	No	Limited overall effectiveness of solution to meet the needs if bulk transfer solutions are adequately addressed. Line has high greenfield construction risk and high project delay risk are identified	2D
23	344	**PECO**	East	PECO Expansion Plan for DOM Window 2023	$302.86	**Yes**	**Yes**	Yes	• Meets performance requirements and efficiently utilizes existing ROW • Most efficient or cost-effective • Provides solid robust performance to meet the needs in the PB-Conastone and BGE areas	• 1A • 1B • 0E Series • 0F • 0G • 0H / 0H2 • 0H2 • 0I • 0J / 0J-2/ 0J-3 • 0K • 0L • 0M • 0N • 0O / 0O2 / 0O3 • 0P / 0P2 / 0P NGME • 0Q / 0Q2 / 0Q3 / 0Q4 • 0R / 0R2 • 0S • 2 / 2A / 2B / 2C / 2D / 2E
24	347	**NextEra**	West/ Northern Virginia	Black Oak-Woodside-Gant, Woodside SVC + Cap Banks	$483.83	**Yes**	**No**	No	Does not provide the needed supply source into the Dominion northern Virginia transmission system (Load Centers)	0E11-3 / 0E11-4 / 0E11-5 / 0E11-6 / 0E11-7 / 0E11-7-A / 0E11-7-B / 0E11-7-B + Yeat / 0E11-7-B +IEC West / 0E11-7-B + Hunterstown -Carrol Rebuild / 0E11-7-B + Hunterstown -Carrol Rebuild + IEC West / 0E11-7-B Final / 0E11-8 / 0E11-9 / 0E11-10 / 0E11-11 / 0E11-12
25	374	**PPL**	East	Otter Creek-Conastone 500 and 230 kV DCT Line	$154.21	**Yes**	**Yes**	Yes	• Most cost-effective or efficient solution to achieve additional East-West bulk transfer reinforcements and also assist with clearing capacity along the PB-Conastone corridor • Line supports the BGE/PEPCO system under outage conditions, Load Deliverability and needed supply source capability into northern Virginia/APS	0E Series (except for 0E2 / 0E3 / 0E6 / 0E6-1 / 0E7)

#	Proposal ID	Proposing Entity	Focus Area (s)	Project Title	Submitted Cost ($M)	Meet Reliability Needs In: 2027 Model	Meet Reliability Needs In: 2028 Model	Selected Y/N	Rationale	Applicable Scenarios
26	385	**NextEra**	East/ Northern Virginia	New 500/230 kV Bartholow substation, new 500/230 kV North Delta substation, new 230 kV Grisham switchyard, new 500/230 kV Goram substation	$1,140.73	**Yes**	**Yes**	No	• New substation (Barthlow) not needed part of the selected solution set • Major substation with 12 - 230 and 500 kV lines terminating into it that could be eliminated • No need for a new North Delta substation (one already approved and well-ahead through process) • Grisham and Goran substations are both new proposed substation, which are both avoided under the PJM selected proposal	• 0O • 0R
27	410	**AEP**	Local AEP	Cloverdale Breaker Reconfiguration	$11.59	**Yes**	**Yes**	Yes	Required part of the PJM 500 kV selected solution for 2022W3	0E11-7-B / 0E11-7-B + Yeat / 0E11-7-B +IEC West / 0E11-7-B + Hunterstown - Carrol Rebuild / 0E11-7-B + Hunterstown - Carrol Rebuild + IEC West / 0E11-7-B Final / 0E11-10 / 0E11-10-A / 0E11-11
28	419	**NextEra**	East/ Northern Virginia	Hunterstown-Doubs-Audobon-Goose Creek	$548.75	**Yes**	**No**	No	The proposed 500 kV line is similar in length to the PJM selected 500 kV line from Otter Creek to Doubs, which is more effective in meeting the reliability need	0H/0H2
29	445	**NextEra**	East	Muddy Creek / Delta-Conastone / Hunterstown-Doubs-Goose Creek Solution	$637.80	**Yes**	**Yes**	No	• Similar 500 kV solution that is planned for construction efficiently and effectively along existing ROW is part of the PJM selected proposal • The selected PJM proposal achieves the needed transfer capability East-West with less impact (fewer lines and much less new substations)	• 2E • 0H / 0H2
30	477	**AEP**	Local AEP	Fieldale-Franklin Rebuild	$74.89	**Yes**	**Yes**	No	Not required to meet the 2022W3 needs with the selected PJM 500 kV solutions (that address the primary need drivers for the window)	N/A

#	Proposal ID	Proposing Entity	Focus Area (s)	Project Title	Submitted Cost ($M)	Meet Reliability Needs In: 2027 Model	Meet Reliability Needs In: 2028 Model	Selected Y/N	Rationale	Applicable Scenarios
21	487	**AEP - Transource**	East	Maryland & Pennsylvania Baseline Reliability Solution	$492.75	**Yes**	**No**	No	• Does not meet the 2027/28 needs • Solution designed predominantly to address the 2027 case needs only • More cost-effective and efficient solutions were offered part of the 2022W3 RTEP • The solutions are less effective than those selected by PJM • Proposal does not offer solutions to the BGE local needs and fails the load deliverability test/needs • Solution is predominantly greenfield	• 1C / 1C-1 • 0A • 0E5 • 0E8-2 • 0E11-7-B+IEC West • 0E11-7-B + Hunterstown-Carrol Rebuild + IEC West • 0E11-8 • 0E11-11 • 0P / 0P2
32	516	**Dominion**	Northern Virginia	Aspen-Doubs Second 500 kV Line	$61.72	**Yes**	**Yes**	Yes	Provides a second 500 kV line into the Load Center area in Dominion and utilizes existing/advacent ROW across the Potomac river	• 1A / 1B / 1C / 1C-1 • 2 / 2A / 2B / 2C / 2D / 2E / 2F • 0E Series • 0F • 0G • 0H / 0H2 • 0I • 0J / 0J-2 / 0J-3 • 0K • 0L • 0M • 0N • 0O / 0O2 /0O3 • 0P / 0P2 / 0P NGME • 0Q / 0Q2 / 0Q3 / 0Q4 • 0R / 0R2 0S
33	524	**AEP**	Local AEP	Opossum Creek and New London Reactors	$8.86	**Yes**	**Yes**	No	Not required to meet the 2022W3 needs with the selected PJM 500 kV solutions (that address the primary need drivers for the window)	N/A
34	530	**NextEra**	East	Muddy Creek / North Delta-Conastone Solution	$166.74	**Yes**	**Yes**	No	Same as for proposal 38	2 / 2A / 2B / 2C / 2D / 2E / 2F
35	537	**AEP**	Local AEP	Fieldale-Franklin Sag Study	$30.19	**Yes**	**Yes**	No	Not required to meet the 2022W3 needs with the selected PJM 500 kV solutions (that address the primary need drivers for the window)	N/A

#	Proposal ID	Proposing Entity	Focus Area (s)	Project Title	Submitted Cost ($M)	Meet Reliability Needs In: 2027 Model	Meet Reliability Needs In: 2028 Model	Selected Y/N	Rationale	Applicable Scenarios
36	548	**LSPower**	ALL	RTEP Window 3 Solution	$2,404.48	**Yes**	**No**	No	• Does not meet the 2027/28 needs • Solution designed predominantly to address the 2027 case needs only • The western 500 kV solution does terminate at the existing Doubs substation and does not offer an outlet capacity from Doubs into the Goose Creek area • More cost-effective and efficient solutions were presented part of the 2022W3 RTEP • The eastern cluster solutions are less effective than those selected by PJM • Proposal does not offer solutions to the BGE local needs and fails the load deliverability test/needs • High constructability risk (ROW owned by Dominion) for the 500 kV UG line portion of proposal from Goose Creek to Beaumeade and technically inferior to the PJM selected 500 kV development in the area.	• 2B • 2C • 0E11-9
37	564	**NextEra**	East/ Northern Virginia	New 500/230 kV Bartholow substation, new 500/230 kV North Delta substation, new 230 kV Grisham switchyard, new 500/230 kV Goram substation	$876.88	**Yes**	**Yes**	No	• New substation (Barthlow) not needed part of the selected solution set • Major substation with 12x230 and 500 kV lines terminating into it that could be eleminated by PJM selected 500 kV solutions • No need for a new North Delta substation (one already approved and well-ahead through process) • Grisham and Goran substations are both new proposed substation, which are both avoided under the PJM selected proposal	0O and 0R

#	Proposal ID	Proposing Entity	Focus Area (s)	Project Title	Submitted Cost ($M)	Meet Reliability Needs In: 2027 Model	Meet Reliability Needs In: 2028 Model	Selected Y/N	Rationale	Applicable Scenarios
38	577	**NextEra**	South	Front Royal-Racefield, Warrenton-Wheeler, North Anna-Lady Smith	$258.38	**Yes**	**Yes**	No	Not required with the development of the needed 500 kV selected proposal by PJM, particularly the third 500 kV feed into Aspen and the looped 500 kV development in Dominion (Aspen-Golden-Mars). Avoids highly sensitive, high risk greenfield ROW	0B
39	598	**NextEra**	ALL	Combination of PEBO 220 + WOP 1F + SOP 8E	$2,036.47	**Yes**	**No**	No	• Solution does not meet the 2027/28 needs and robustness test. • Proposals relies heavily on 230 kV developments which introduces significant impacts in the East that could be effectively and mitigated by just 2x500 kV developments in the same area, predominantly on existing ROWs • For this combination proposal to meet the 2027/28 needs, an expensive ~4Bn additional 2x230 kV circuits are required across the Chesapeake bay • Even with the above development, the solution fails the Load Deliverability test in BGE and SW-MAAC	0C
40	600	**PECO**	East	Exelon Replacement Upgrades	$423.79	**No**	**No**	No	The proposal is upgrades to an existing Exelon system and is not enough to address the violations identified in the 2022 Window 3	N/A
41	606	**PPL**	Local Other	Juniata-Lewistown 230 kV No. 2 line	$141.16	**Yes**	**Yes**	No	Not required to meet the 2022W3 needs with the selected PJM 500 kV solutions (that address the primary need drivers for the window)	N/A
42	629	**AEP**	Local AEP	Scottsville-Bremo Rebuild	$31.31	**Yes**	**Yes**	No	Not required to meet the 2022W3 needs with the selected PJM 500 kV solutions (that address the primary need drivers for the window)	N/A

#	Proposal ID	Proposing Entity	Focus Area (s)	Project Title	Submitted Cost ($M)	Meet Reliability Needs In: 2027 Model	Meet Reliability Needs In: 2028 Model	Selected Y/N	Rationale	Applicable Scenarios
43	631	**NextEra**	East	Muddy Creek / North Delta-Conastone Solution	$184.47	**Yes**	**Yes**	No	Same as for proposal 38	2 / 2A / 2B / 2C / 2D / 2E / 2F
44	637	**PSEG**	East	Proposal D-Conastone-Doubs 500 kV	$684.22	**Yes**	**Yes**	Yes	Addresses the reliability needs effectively and efficiently (in combination with PPL's proposal 374)	• 0E Series (except for 0E2 / 0E3 / 0E6 / 0E6-1 / 0E7) • 0K • 0O • 0R
45	642	**NextEra**	West/ Northern Virginia	502 Junction-Black Oak-Woodside-Gant, Woodside SVC + Cap Banks, Gant-Farmwell, Cochran Tap-Round Table	$747.31	**Yes**	**No**	No	The Gant-Farmwell and Cochran Tap-Round Table are, not as robust as the selected 500 kV loop established by the selected DOM proposal between Aspen, Golden and Mars	0E11-3 / 0E11-4 / 0E11-5 / 0E11-6 / 0E11-7 / 0E11-7-A / 0E11-7-B / 0E11-7-B + Yeat / 0E11-7-B +IEC West / 0E11-7-B + Hunterstown -Carrol Rebuild / 0E11-7-B + Hunterstown -Carrol Rebuild + IEC West / 0E11-7-B Final / 0E11-8 / 0E11-9 / 0E11-10 / 0E11-11 / 0E11-12
46	660	**PEPCO**	East	West Cooper BGE-PEPCO	$1,105.62	**Yes**	**Yes**	Yes	• Meets performance requirements and efficiently utilizes existing ROW • Most efficient or cost-effective • provides solid robust performance to meet the needs in the PB-Conastone and BGE areas	• 1A • 1B • 0E Series • 0F • 0G • 0H / 0H2 • 0H2 • 0I • 0J / 0J-2/ 0J-3 • 0K • 0L • 0M • 0N • 0O / 0O2 / 0O3 • 0P / 0P2 / 0P NGME • 0Q / 0Q2 / 0Q3 / 0Q4 • 0R / 0R2 • 0S • 2 / 2A / 2B / 2C / 2D / 2E
47	663	**NextEra**	Northern Virginia/ South	Front Royal-Racefield, Warrenton-Rixlew, Warrenton-Hourglass, Mars-Ocean Court-Davis Drive	$284.17	**Yes**	**Yes**	No	Not required with the development of the needed 500 kV selected proposal by PJM, particularly the 3rd 500 kV feed into Aspen and the looped 500 kV development in Dominion (Aspen-Golden-Mars). Avoids highly sensitive, high risk greenfield ROW	0L

#	Proposal ID	Proposing Entity	Focus Area (s)	Project Title	Submitted Cost ($M)	Meet Reliability Needs In: 2027 Model	Meet Reliability Needs In: 2028 Model	Selected Y/N	Rationale	Applicable Scenarios
48	671	**Dominion**	West/ South	Lines No. 541 (Front Royal to Morrisville) Rebuild	$299.03	**Yes**	**Yes**	No	Not required with the PJM selected 500 kV solution.	• 2 / 2A / 2B / 2E • 0G • 0H / 0H2 • 0I • 0J / 0J-2 / 0J-3 • 0K • 0L • 0M • 0N • 0O / 0O2 / 0O3 • 0P / 0P2 / 0P NGME • 0Q / 0Q2 / 0Q3 / 0Q4 • 0R / 0R2 • 0S
49	676	**NextEra**	West/ Northern Virginia	Black Oak-Stonewall-Gant, Stonewall SVC + Cap Banks, Gant-Farmwell, Cochran Tap-Round Table Solution	$552.49	**Yes**	**No**	No	Not as robust as the selected 500 kV loop established by the selected DOM proposal between Aspen, Golden and Mars	0E11-3 / 0E11-4 / 0E11-5 / 0E11-6 / 0E11-7 / 0E11-7-A / 0E11-7-B / 0E11-7-B + Yeat / 0E11-7-B +IEC West / 0E11-7-B + Hunterstown -Carrol Rebuild / 0E11-7-B + Hunterstown -Carrol Rebuild + IEC West / 0E11-7-B Final / 0E11-8 / 0E11-9 / 0E11-10 / 0E11-11 / 0E11-12
50	685	**NextEra**	West	Ft. Martin-Black Oak-Woodside, Woodside SVC + Cap Banks Solution	$609.78	**Yes**	**No**	No	Does not provide the needed supply source into the Dominion northern Virginia transmission system (Load Centers)	0E11-3 / 0E11-4 / 0E11-5 / 0E11-6 / 0E11-7 / 0E11-7-A / 0E11-7-B / 0E11-7-B + Yeat / 0E11-7-B +IEC West / 0E11-7-B + Hunterstown -Carrol Rebuild / 0E11-7-B + Hunterstown -Carrol Rebuild + IEC West / 0E11-7-B Final / 0E11-8 / 0E11-9 / 0E11-10 / 0E11-11 / 0E11-12
51	691	**PEPCO**	East	Mid-Atlantic Power Pathway (MAPP)	$1,990.28	**No**	**No**	No	Project not considered due to supply chain and long lead times requirements	N/A
52	692	**Dominion**	Northern Virginia	Data Center Alley Local solution-New 500 kV/230 kV Aspen-Golden & Golden-Mars lines	$1,058.45	**Yes**	**Yes**	Yes	Required for reliability needs. Most efficient or cost-effective solution. Offers robust solution to serve the data center loads in the dominion zone (northern Virginia) and also offers parallel 500 kV path to the single 500 kV line between Goose Creek and Wishing Star	• 1A / 1B / 1C / 1C-1 • 2 / 2C / 2D / 2E / 2F • 0E Series • 0F • 0G • 0H / 0H2 • 0I • 0J / 0J-2 / 0J-3 • 0K • 0L • 0M • 0N • 0O / 0O2 / 0O3 • 0P / 0P2 / 0P NGME • 0Q / 0Q2 / 0Q3 / 0Q4 • 0R / 0R2 • 0S

#	Proposal ID	Proposing Entity	Focus Area (s)	Project Title	Submitted Cost ($M)	Meet Reliability Needs In: 2027 Model	Meet Reliability Needs In: 2028 Model	Selected Y/N	Rationale	Applicable Scenarios
53	704	**Dominion**	South	Hollymead-Gordonsville Line No. 2135 Rebuild	$36.89	**Yes**	**Yes**	No	Dominion proposal No. 211 chosen over proposal No. 704. Both proposals include a wreck and rebuild of 230 kV Line No. 2135. However proposal No. 704 utilizes double-circuit capable 230 kV poles, whereas proposal No. 211 utilizes double-circuit capable 500/230 kV poles.	• 0E11-7-B / 0E11-7-B + Yeat / 0E11-7-B +IEC West / 0E11-7-B + Hunterstown - Carrol Rebuild / 0E11-7-B + Hunterstown -Carrol Rebuild + IEC West • 0G • 0H / 0H2 • 0I • 0J / 0J-2 / 0J-3 • 0K • 0L • 0M • 0N • 0O / 0O2 / 0O3 • 0P / 0P2 / 0P NGME • 0Q / 0Q2 / 0Q3 / 0Q4 • 0R / 0R2 • 0S
54	711	**Dominion**	South	Regional Solution - 500 kV North Anna-Wishing Star Upgrades	$1,227.84	**Yes**	**Yes**	Yes *(Partial)*	Offers robust solution to serve the data center loads in the dominion zone (northern Virginia). Proposal utilizes efficiently the existing ROW between Morrisville and Wishing Star. Segment between Morssisville and North Anna eliminated by PJM 500 kV solution.	• 1A / 1B / 1C / 1C-1 • 0E Series • 0F • 0G • 0H / 0H2 • 0I • 0J / 0J-2 / 0J-3 • 0K • 0L • 0M • 0N • 0O / 0O2 / 0O3 • 0P / 0P2 / 0P NGME • 0Q / 0Q2 / 0Q3 / 0Q4 • 0R / 0R2 • 0S
55	719	**NextEra**	West	Ft. Martin-Black Oak-Pike, Pike SVC + Cap Banks Solution	$600.90	**Yes**	**No**	No	Does not provide the needed supply source into the Dominion northern Virginia transmission system (Load Centers)	0E11-3 / 0E11-4 / 0E11-5 / 0E11-6 / 0E11-7 / 0E11-7-A / 0E11-7-B / 0E11-7-B + Yeat / 0E11-7-B +IEC West / 0E11-7-B + Hunterstown -Carrol Rebuild / 0E11-7-B + Hunterstown -Carrol Rebuild + IEC West / 0E11-7-B Final / 0E11-8 / 0E11-9 / 0E11-10 / 0E11-11 / 0E11-12

#	Proposal ID	Proposing Entity	Focus Area (s)	Project Title	Submitted Cost ($M)	Meet Reliability Needs In: 2027 Model	Meet Reliability Needs In: 2028 Model	Selected Y/N	Rationale	Applicable Scenarios
56	728	**NextEra**	East/ Northern Virginia	Barnhart Substation, Bartholow Substation, Barnhart-Bartholow-Goose Creek solution	$385.36	**Yes**	**No**	No	• Does not provide the needed supply source into the Dominion northern Virginia transmission system (Load Centers) • Barthlow substation deemed not required with the PJM selected proposal, which has much less overall impact (many 500 and 230 kV greenefield lines compared to just 2x500 kV lines under PJM proposal and without Barthlow sub)	0E2
57	731	**Dominion**	South	Locks Substation 230/115 kV Transformer Upgrade	$7.14	**Yes**	**Yes**	Yes	Required for reliability needs. Most efficient or cost-effective solution	0E11-7-B / 0E11-7-B + Yeat / 0E11-7-B +IEC West / 0E11-7-B + Hunterstown - Carrol Rebuild / 0E11-7-B + Hunterstown - Carrol Rebuild + IEC West / 0E11-7-B Final • 0G • 0H / 0H2 • 0I • 0J / 0J-2 / 0J-3 • 0K • 0L • 0M • 0N • 0O / 0O2 / 0O3 • 0P / 0P2 / 0P NGME • 0Q / 0Q2 / 0Q3 / 0Q4 • 0R / 0R2 • 0S
58	741	**PSEG**	East	Proposal G - Peach Bottom-New Brandon Shores 500 kV; Peach Bottom-Doubs 500 kV	$1,065.32	**Yes**	**Yes**	No	• Selected incumbent proposal addresses the needs for bulk transfers between Peach Bottom and Conastone (in combination with other proposals) predominantly using existing ROW in the PB-Conastone corridor • PSEG proposal to develop a line from Conastone to Doubs has already been selected part of Proposal No. 637 - in combination with PPL proposal 374	• 0E4-1-2 / 0E11-7-B Final • 0Q

#	Proposal ID	Proposing Entity	Focus Area (s)	Project Title	Submitted Cost ($M)	Meet Reliability Needs In: 2027 Model	Meet Reliability Needs In: 2028 Model	Selected Y/N	Rationale	Applicable Scenarios
59	766	**NextEra**	South	Front Royal-Racefield, Warrenton-Wheeler	$239.59	**Yes**	**Yes**	No	Not required with the development of the needed 500 kV selected proposal by PJM, particularly the 3rd 500 kV feed into Aspen and the looped 500 kV development in Dominion (Aspen-Golden-Mars). Avoids highly sensitive, high risk greenfield ROW	QT3
60	808	**PSEG**	East	Proposal F - Peach Bottom-New Raphael-Waugh Chapel 500 kV; Peach Bottom-Doubs 500 kV	$1,150.80	**Yes**	**Yes**	No	Immediate need proposal to address the Peach Bottom deactivation needs in BGE has a much lower risk of construction, more cost-effective and efficient solution	• 0E4-1-1 / 0E13 / 0E13-1 • 0S
61	837	**POTOED - FirstEnergy**	East/ West/ Northern Virginia	Data Center Reinforcement Proposal No. 1 • 1 - 500 kV circuits from Fort Martin-Doubs • 1 - 500 kV circuit from Prutnytown-Meadow Brook-Doubs • Second 500 kV from Doubs-Aspen and Rebuild the existing Doubs-Goose Creek 500 kV • Rebuild Hunterstown-Caroll 115/138 kV line for 230 kV double circuit construction	$2,991.77	**Yes**	**No**	Yes *(partial)*	• Proposal attempts to address the west-east transfer needs and voltage collapse concerns along the transfer path • PJM analysis indicated that the system reliability benefits more from spreading the reinforcements for transfer between the East and West corridors instead of just the Western corridor • All options provide injections into Doubs, however, no solutions offered to debottleneck the Doubs-Goose Creek corridor • Currently there is no need for 2x500 kV double circuit development along the West-East corridor • only 1x500kV is required part of the PJM selected solution • Cost is higher than similar 500 kV proposals by other entities that provide stronger cost containment provisions • Proposal utilizes existing ROWs for parts of the projects including the new Doubs-Aspen 500 kV and Huntertown-Caroll 230 kV, which	• 1A / 1B / 1C / 1C-1 • 2 / 2A / 2B / 2C / 2D / 2E / 2F • 0E Series (except for 0E8-2 / 0E11-3 / 0E11-5 / 0E11-6) • 0L

#	Proposal ID	Proposing Entity	Focus Area (s)	Project Title	Submitted Cost ($M)	Meet Reliability Needs In: 2027 Model	Meet Reliability Needs In: 2028 Model	Selected Y/N	Rationale	Applicable Scenarios
									both components are in the list of PJM selected projects	
62	846	**NextEra**	East/ West/ Northern Virginia	Hunterstown-Doubs-Goose Creek, Black Oak-Woodside-Goose Creek, Stonewall SVC + Cap Banks	$892.94	**Yes**	**No**	No	• The proposed 500 kV line is similar in length to the PJM selected 500 kV line from Otter Creek to Doubs, which is more effective in meeting the reliability need • PJM selected 500 kV combination is more effective in meeting the reliability need	0H/0H2
63	853	**NextEra**	West/ Northern Virginia	502 Junction-Black Oak-Woodside-Gant, Woodside SVC + Cap Banks	$683.55	**Yes**	**Yes**	Yes *(partial)*	• Effective solution to address the reliability needs for West to East transfers and offers a 3rd 500 kV supply line to the load center in Dominion • The selected component is modified to bypass the Black Oak and terminate at Aspen (original proposal terminate at Gant)	0E11-3 / 0E11-4 / 0E11-5 / 0E11-6 / 0E11-7 / 0E11-7-A / 0E11-7-B / 0E11-7-B + Yeat / 0E11-7-B +IEC West / 0E11-7-B + Hunterstown -Carrol Rebuild / 0E11-7-B + Hunterstown -Carrol Rebuild + IEC West / 0E11-7-B Final / 0E11-8 / 0E11-9 / 0E11-10 / 0E11-11 / 0E11-12
64	856	**AEP**	Local AEP	Leesville-Altavista Rebuild	$28.85	**Yes**	**Yes**	No	Not required to meet the 2022W3 needs with the selected PJM 500kV solutions (that address the primary need drivers for the window)	N/A

#	Proposal ID	Proposing Entity	Focus Area (s)	Project Title	Submitted Cost ($M)	Meet Reliability Needs In: 2027 Model	Meet Reliability Needs In: 2028 Model	Selected Y/N	Rationale	Applicable Scenarios
65	858	**AEP - Transource**	Northern Virginia	Stork-Flys 500 kV Greenfield Line and Substations	$510.44	**Yes**	**Yes**	No	High constructability risk (proposes use of Loudoun County roadways which was deemed high concern by VDOT officials) and technically inferior to the PJM selected 500 kV development in the area.	• 2A • 0A • 0M
66	904	**AEP - Transource**	West/ South	Joshua Falls-Yeat 765 kV Greenfield Line and Substation	$1,048.10	**Yes**	**Yes**	No	Project proposes new, greenfield 765 kV development close to 135 miles long. Introduces high risk to area reliability due to delayed project construction and in service year risk. PJM selected 500 kV solution addresses the need cost-effective and efficiently. The 765 kV solution could be pursued part of the longer term solutions in the area depending on how load and generation materialize.	• 2F • 0A • 0E8 / 0E8-1/ 0E8-1-1 / 0E8-2 / 0E8-2-1 / 0E8-2-2 / 0E11-4 / 0E11-5 / 0E11-7-B + Yeat / 0E11-10-A / 0E11-11
67	923	**Dominion**	South	Second 500 kV line from Lexington to Dooms	$232.18	**Yes**	**Yes**	No	Not required under the 2027/28 analysis scenario	• 0G • 0H / 0H2 • 0I • 0J / 0J-2 / 0J-3 • 0K • 0L • 0M • 0N • 0O / 0O2 / 0O3 • 0P / 0P2 / 0P NGME • 0Q / 0Q2 / 0Q3 / 0Q4 • 0R / 0R2 • 0S

#	Proposal ID	Proposing Entity	Focus Area (s)	Project Title	Submitted Cost ($M)	Meet Reliability Needs In: 2027 Model	Meet Reliability Needs In: 2028 Model	Selected Y/N	Rationale	Applicable Scenarios
68	948	**NextEra**	East/ Northern Virginia	New 500/230 kV Bartholow substation, new 500/230 kV North Delta substation, new 230 kV Grisham switchyard, new 500/230 kV Goram substation, and Keeney to Waugh Chapel tie-in.	$5,381.25 *	**Yes**	**Yes**	No	• New substation (Barthlow) not needed part of the selected solution set • Major substation with 12x230 and 500kV lines terminating into it that could be eliminated by PJM selected 500 kV solutions • No need for a new North Delta substation (one already approved and well-ahead through process) • Grisham and Goran substations are both new proposed substation, which are both avoided under the PJM selected proposal • The proposal includes expensive ~4Bn and high constructability/schedule risk additional 2x230 kV circuits across the Chesapeake bay	• 0E4-1-3 • 0I • 0J / 0J-2 / 0J-3 • 0B
69	951	**NextEra**	West/ Northern Virginia	Black Oak-Gore-Goose Creek, Pike SVC + Cap Bank Solution	$419.86	**Yes**	**No**	No	Does not provide the needed supply source into the Dominion northern Virginia transmission system (Load Centers)	0E11-3 / 0E11-4 / 0E11-5 / 0E11-6 / 0E11-7 / 0E11-7-A / 0E11-7-B / 0E11-7-B + Yeat / 0E11-7-B +IEC West / 0E11-7-B + Hunterstown -Carrol Rebuild / 0E11-7-B + Hunterstown -Carrol Rebuild + IEC West / 0E11-7-B Final / 0E11-8 / 0E11-9 / 0E11-10 / 0E11-11 / 0E11-12
70	962	**PSEG**	East	Proposal H - Peach Bottom-Doubs 500 kV (Circuits No. 1 and No. 2)	$977.71	**Yes**	**Yes**	No	See comments associated with Proposal No. 741	N/A
71	967	**Dominion**	South	Charlottesville-Hollymead Line No. 2054 Rebuild	$183.48	**Yes**	**Yes**	Yes *(partial)*	Required for reliability needs. Considers future load growth in Culpeper and Louisa area by supporting 500 kV developments with double-circuit capable 500/230 kV poles.	• 0E11-7-B Final • 0G • 0H / 0H2 • 0I • 0J / 0J-2 / 0J-3 • 0K • 0L • 0M • 0N • 0O / 0O2 / 0O3 • 0P / 0P2 / 0P NGME • 0Q / 0Q2 / 0Q3 / 0Q4 • 0R / 0R2 • 0S

#	Proposal ID	Proposing Entity	Focus Area (s)	Project Title	Submitted Cost ($M)	Meet Reliability Needs In: 2027 Model	Meet Reliability Needs In: 2028 Model	Selected Y/N	Rationale	Applicable Scenarios
72	977	**AEP - Transource**	South	Yeat 500/230 kV Greenfield Station	$232.14	**Yes**	**Yes**	No	Project proposes new, greenfield 765 kV development close to 135 miles long. Introduces high risk to area reliability due to delayed project construction and in service year risk. PJM selected 500 kV solution addresses the need cost-effective and efficiently. The 765 kV solution could be pursued part of the longer term solutions in the area depending on how load and generation materialize.	• 0A • 0E6 / 0E6-1 / 0E7

Critical Substation Planning Analysis

The Critical Substation Planning Analysis (CSPA)[4] was created as an extension of the PJM Transmission Owners' Attachment M-4 process. The purpose of the CSPA is to conduct additional screening as part of a five-year annual PJM RTEP cycle to ensure no new CIP-14 facilities is introduced to the PJM system as the transmission network evolves.

PJM CSPA evaluates system reinforcements, consistent with RTEP CSPA methodology as described in Section 2.9 of Manual 14B. CSPA is performed to identify Instability, Uncontrolled Separation, or Cascading resulting in one or more of the following outcomes due to the loss of all voltage levels 69 kV and above at a single transmission facility that meet the NERC CIP-14 substation criteria.

- Loss of load approaching 1000 MW
- Three levels of facility trips
- Case non-convergence issue in steady-state or dynamic analysis covering both angular and voltage stability tests

For 2022 Window 3, PJM conducted CSPA for proposals in 12 scenarios based on PJM RTEP 2028 summer peak case. No new critical substation was identified due to selected system upgrades in 2020 Window 3.

Power System Stability Analysis

The 2022 Window 3 needs are predominantly driven by steady state (both thermal and voltage) reliability violations. However, PJM conducted stability analysis to ensure the final recommended solution meet all applicable planning stability criteria (PJM, NERC, and Local Transmission Owner criteria) with the PJM-selected reinforcements capturing the impact of the load increase, change in generation resource mix and dispatch pattern. The dynamic performance of PJM system with the final selected solution was analyzed from three key stability aspects: transient (angle) stability, small signal (damping) stability and transient voltage stability.

Critical system conditions for stability analysis on the PJM system are generally characterized by light load and peak load conditions. In this stability study, PJM RTEP 2028 summer peak and light load dynamics cases were used. The assumptions used for generation dispatch can be critical to the stability results. PJM followed PJM's stability dispatch methodology to create conservative system conditions for stability analysis. Dynamic models of the proposed STATCOMs at Stonewall, Mars, Beaumeade, Granite and Brighton stations were properly incorporated in the study dynamics cases.

PJM selected more than 70 critical NERC Planning events (P1, P4, P6 and P7) at 22 key substations associated with the final solution from East, West, South and Northern Virginia data center loads areas. The critical contingencies were selected based on system topology, loading interruption size by contingency events, and the size of dynamic reactive devices, as well as past study experiences and engineering judgement. PSS/E, which is well-accepted

[4] *See* PJM Manual 14B, section 2.9

power system analysis software, was used as a stability simulation tool. The findings from the stability study are summarized as follows:

- No potential stability criteria violations were identified.
- There are no transient (angle) stability issues at major generation stations including Peach Bottom, Limerick and North Anna nuclear plants.
- PJM system demonstrated acceptable damping performance after system disturbances by the contingencies.
- No transient voltage recovery performance issue around major load centers was identified.

Appendix A: Scope of Final Reliability Analysis

PJM seeks technical solutions, also called proposals, to resolve potential reliability criteria violations on facilities identified below in accordance with all applicable planning criteria (PJM, NERC, SERC, RFC and Local Transmission Owner criteria).

Criterion Applied by PJM for this Proposal Window

- 2027–28 Summer
- Baseline Thermal and Voltage N-1 Contingency Analysis
- Generator Deliverability and Common Mode Reliability Analysis
- N-1-1 Thermal and Voltage Analysis and Voltage Collapse
- Load Deliverability Thermal and Voltage Analysis
- Dynamic Stability Assessment
- 2027–28 Winter
- Baseline Thermal and Voltage N-1 Contingency Analysis
- Generator Deliverability and Common Mode Reliability Analysis
- N-1-1 Thermal and Voltage Analysis and Voltage Collapse
- Load Deliverability Thermal and Voltage Analysis
- Dynamic Stability Assessment
- 2027–28 Light Load
- Baseline Thermal and Voltage N-1 Contingency Analysis
- Generator Deliverability and Common Mode Reliability Analysis

Appendix B: Window 3 Scenarios and Screening Performance

Listed below are high-level descriptions and screening performance of some of the major scenarios.

Scenario 1A

Scenario Components

Primary Incumbent TOs Proposals – regional components

- Exelon: 2022-W3-344/660
- Rebuild 5012 500 kV (will be looped in to West Cooper and Gracetone)
- West Cooper-Peach Bottom South New 500 kV Line
- West Cooper-High Ridge 500 kV
- FE: 2022-W3-837
- Fort Martin-Doubs 500 No. 1
- DOM: 2022-W3-711
- New 500 kV Line (North Anna-Spotsylvania)
- New 500 kV Line (Spotsylvania to Vint Hill)
- New 500 kV Line (Vint Hill to Wishing Star)
- DOM/FE: 2022-W3-516/837
- Aspen-Doubs Second 500 kV Line
- Line No. 514 (Goose Creek-Doubs) Rebuild
- DOM: 2022-W3-692 (include 230 kV)
- Aspen-Golden 500 kV Line Build
- New Mars-Golden 500 kV
- Aspen to Goose Creek 500 kV

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	34
500 kV Overloads	1
345 kV Overloads	2
230 kV Overloads	1
138 kV Overloads	20
115 kV Overloads	6

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	74
500 kV Overloads	14
345 kV Overloads	0
230 kV Overloads	27
138 kV Overloads	14
115 kV Overloads	10

Scenario 1B

Scenario Components

Primary Incumbent TOs Proposals – No Dominion South – regional components

- Exelon: 2022-W3-344/660
- Rebuild 5012 500 kV (will be looped in to West Cooper and Gracetone)
- West Cooper-Peach Bottom South New 500 kV Line
- West Cooper-High Ridge 500 kV
- FE: 2022-W3-837
- Fort Martin-Doubs 500 No. 1
- DOM/FE: 2022-W3-516/837
- Aspen-Doubs Second 500 kV Line
- Line No. 514 (Goose Creek-Doubs) Rebuild
- DOM: 2022-W3-692 (include 230 kV)
- Aspen-Golden 500 kV Line Build
- New Mars-Golden 500 kV
- Aspen to Goose Creek 500 kV

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	54
500 kV Overloads	10
345 kV Overloads	2
230 kV Overloads	6
138 kV Overloads	26
115 kV Overloads	5

Scenario 1C

Scenario Components

Primary Incumbent TOs Proposals – regional components – use TRANSRC ID 487 east component (IEC-East)

- Transource: 2022-W3-487 IEC-East
- Furnace Run 500/230 kV station
- Furnace Run-Conastone 230 kV
- Furnace Run-Gracetone 230 kV
- FE: 2022-W3-837
- Fort Martin-Doubs 500 No. 1
- DOM: 2022-W3-711
- New 500 kV Line (North Anna-Spotsylvania)
- New 500 kV Line (Spotsylvania to Vint Hill)
- New 500 kV Line (Vint Hill to Wishing Star)
- DOM/FE: 2022-W3-516/837
- Aspen-Doubs Second 500 kV Line
- Line No. 514 (Goose Creek-Doubs) Rebuild
- DOM: 2022-W3-692 (include 230 kV)
- Aspen-Golden 500 kV Line Build
- New Mars-Golden 500 kV
- Aspen to Goose Creek 500 kV

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	49
500 kV Overloads	2
345 kV Overloads	0
230 kV Overloads	5
138 kV Overloads	25
115 kV Overloads	11

Scenario 1C-1

Scenario Components

Primary Incumbent TOs Proposals – regional components – use TRANSRC ID 487 east component (IEC-East) + b3737

- Transource: 2022-W3-487 IEC-East
- Furnace Run 500/230 kV station
- Furnace Run-Conastone 230 kV
- Furnace Run-Gracetone 230 kV
- B3737
- North Delta 500/230 and N. Delta-Graceton 230 kV
- FE: 2022-W3-837
- Fort Martin-Doubs 500 No. 1
- DOM: 2022-W3-711
- New 500 kV Line (North Anna-Spotsylvania)
- New 500 kV Line (Spotsylvania to Vint Hill)
- New 500 kV Line (Vint Hill to Wishing Star)
- DOM/FE: 2022-W3-516/837
- Aspen-Doubs Second 500 kV Line
- Line No. 514 (Goose Creek-Doubs) Rebuild
- DOM: 2022-W3-692 (include 230 kV)
- Aspen-Golden 500 kV Line Build
- New Mars-Golden 500 kV
- Aspen to Goose Creek 500 kV

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	**40**
500 kV Overloads	**1**
345 kV Overloads	**0**
230 kV Overloads	**2**
138 kV Overloads	**23**
115 kV Overloads	**10**

Scenario 2

Scenario Components

Primary Incumbent TOs Proposals – regional components – Upgrade F Royal-Morsvl + NextEra - ND – Conastone + Full DOM local

- NEET: 2022-W3-530
- North Delta-Conastone 500 kV
- FE: 2022-W3-837
- Fort Martin-Doubs 500 No. 1
- DOM: 2022-W3-671
- Line No. 541 (Front Royal to Morrisville) Rebuild
- DOM/FE: 2022-W3-516/837
- Aspen-Doubs Second 500 kV Line
- Line No. 514 (Goose Creek-Doubs) Rebuild
- DOM: 2022-W3-692 (include 230 kV)
- Aspen-Golden 500 kV Line Build
- New Mars-Golden 500 kV
- Aspen to Goose Creek 500 kV

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	88
500 kV Overloads	17
345 kV Overloads	1
230 kV Overloads	16
138 kV Overloads	32
115 kV Overloads	12

Scenario 2A

Scenario Components

Primary Incumbent TOs Proposals – regional components – Upgrade F Royal-Morsvl + NextEra - ND – Conastone + TRANSC - 500 kV UG

- NEET: 2022-W3-530
- North Delta-Conastone 500 kV
- FE: 2022-W3-837
- Fort Martin-Doubs 500 No. 1
- DOM: 2022-W3-671
- Line No. 541 (Front Royal to Morrisville) Rebuild
- DOM/FE: 2022-W3-516/837
- Aspen-Doubs Second 500 kV Line
- Line No. 514 (Goose Creek-Doubs) Rebuild
- Transource: 2022-W3-858
- Stork-Flys 500 kV Underground Line

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	83
500 kV Overloads	14
345 kV Overloads	1
230 kV Overloads	17
138 kV Overloads	32
115 kV Overloads	11

Scenario 2B

Scenario Components

Primary Incumbent TOs Proposals – regional components – Upgrade F Royal-Morsvl + NextEra - ND – Conastone + LSP - 500 kV UG

- NEET: 2022-W3-530
- North Delta-Conastone 500 kV
- FE: 2022-W3-837
- Fort Martin-Doubs 500 No. 1
- DOM: 2022-W3-671
- Line No. 541 (Front Royal to Morrisville) Rebuild
- DOM/FE: 2022-W3-516/837
- Aspen-Doubs Second 500 kV Line
- Line No. 514 (Goose Creek-Doubs) Rebuild
- LS Power: 2022-W3-548
- Goose Creek-Beaumeade 500 kV

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	96
500 kV Overloads	17
345 kV Overloads	1
230 kV Overloads	24
138 kV Overloads	32
115 kV Overloads	12

Scenario 2C

Scenario Components

Primary Incumbent TOs Proposals – regional components – NextEra - ND – Conastone + LSP - West 500 kV FRoyl-Vhill

- NEET: 2022-W3-530
- North Delta-Conastone 500 kV
- FE: 2022-W3-837
- Fort Martin-Doubs 500 No. 1
- LS Power: 2022-W3-548
- Front Royal –VintHill 500 kV
- DOM/FE: 2022-W3-516/837
- Aspen-Doubs Second 500 kV Line
- Line No. 514 (Goose Creek-Doubs) Rebuild
- DOM: 2022-W3-692 (include 230 kV)
- Aspen-Golden 500 kV Line Build
- New Mars-Golden 500 kV
- Aspen to Goose Creek 500 kV

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	48
500 kV Overloads	6
345 kV Overloads	0
230 kV Overloads	1
138 kV Overloads	25
115 kV Overloads	11

Scenario 2D

Scenario Components

Primary Incumbent TOs Proposals – regional components – NextEra - ND – Conastone + PSEG Bramb-HinsonsF 500 kV

- NEET: 2022-W3-530
- North Delta-Conastone 500 kV
- FE: 2022-W3-837
- Fort Martin-Doubs 500 No. 1
- PSEG: 2022-W3-325
- Brambleton-Hinsons Ford 500 kV
- DOM/FE: 2022-W3-516/837
- Aspen-Doubs Second 500 kV Line
- Line No. 514 (Goose Creek-Doubs) Rebuild
- DOM: 2022-W3-692 (include 230 kV)
- Aspen-Golden 500 kV Line Build
- New Mars-Golden 500 kV
- Aspen to Goose Creek 500 kV

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	49
500 kV Overloads	6
345 kV Overloads	0
230 kV Overloads	2
138 kV Overloads	25
115 kV Overloads	11

Scenario 2E

Scenario Components

Primary Incumbent TOs Proposals – regional components – NextEra - ND – Conastone + Hunt-Doubs 500 kV

- NEET: 2022-W3-530
- North Delta-Conastone 500 kV
- NEET: 2022-W3-445
- Hunterstown -Doubs 500 kV
- DOM: 2022-W3-671
- Line No. 541 (Front Royal to Morrisville) Rebuild
- DOM/FE: 2022-W3-516/837
- Aspen-Doubs Second 500 kV Line
- Line No. 514 (Goose Creek-Doubs) Rebuild
- DOM: 2022-W3-692 (include 230 kV)
- Aspen-Golden 500 kV Line Build
- New Mars-Golden 500 kV
- Aspen to Goose Creek 500 kV

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	84
500 kV Overloads	14
345 kV Overloads	2
230 kV Overloads	22
138 kV Overloads	34
115 kV Overloads	6

Scenario 2F

Scenario Components

Primary Incumbent TOs Proposals – regional components – TRASRC - 765 kV + NextEra - ND – Conastone + Full DOM local

- NEET: 2022-W3-530
- North Delta-Conastone 500 kV
- Transource: 2022-W3-904
- Joshua Falls to Yeat 765 kV
- DOM/FE: 2022-W3-516/837
- Aspen-Doubs Second 500 kV Line
- Line No. 514 (Goose Creek-Doubs) Rebuild
- DOM: 2022-W3-692 (include 230 kV)
- Aspen-Golden 500 kV Line Build
- New Mars-Golden 500 kV
- Aspen to Goose Creek 500 kV

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	78
500 kV Overloads	10
345 kV Overloads	0
230 kV Overloads	10
138 kV Overloads	33
115 kV Overloads	11

Scenario 0A

Scenario Components

- Transource: 2022-W3-487
- Transource: 2022-W3-904
- Transource: 2022-W3-977
- Transource: 2022-W3-858

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	18
500 kV Overloads	1
345 kV Overloads	1
230 kV Overloads	4
138 kV Overloads	8
115 kV Overloads	1

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	113
500 kV Overloads	13
345 kV Overloads	0
230 kV Overloads	47
138 kV Overloads	11
115 kV Overloads	27

Scenario 0B

Scenario Components

- NEET: 2022-W3-175

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	23
500 kV Overloads	2
345 kV Overloads	2
230 kV Overloads	2
138 kV Overloads	13
115 kV Overloads	2

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	28
500 kV Overloads	4
345 kV Overloads	0
230 kV Overloads	9
138 kV Overloads	3
115 kV Overloads	4

7,500 MW OSW Screening Performance

Overload	Number of Overloads
Total Overloads	52
500 kV Overloads	9
345 kV Overloads	0
230 kV Overloads	24
138 kV Overloads	4
115 kV Overloads	4

11,000 MW OSW Screening Performance

Overload	Number of Overloads
Total Overloads	74
500 kV Overloads	12
345 kV Overloads	0
230 kV Overloads	31
138 kV Overloads	4
115 kV Overloads	4

Scenario 0B2

Scenario Components

- NEET: 2022-W3-175
- Removal of two 230 kV line from Warrenton-Rixlew/Hourglass, 500 kV line from Front Royal-New Wishing Star

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	28
500 kV Overloads	3
345 kV Overloads	0
230 kV Overloads	10
138 kV Overloads	3
115 kV Overloads	4

Scenario 0B3

2028 Scenario Components

- NEET: 2022-W3-175
- Removal of two 230 kV line from Warrenton-Rixlew/Hourglass, 500 kV line from Front Royal-New Wishing Star
- Removal of Keeney to Waugh Chapel 230 kV circuit 1 and 2

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	40
500 kV Overloads	6
345 kV Overloads	0
230 kV Overloads	20
138 kV Overloads	2
115 kV Overloads	7

Scenario 0C

Scenario Components

- NEET: 2022-W3-598

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	23
500 kV Overloads	2
345 kV Overloads	2
230 kV Overloads	2
138 kV Overloads	13
115 kV Overloads	2

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	39
500 kV Overloads	6
345 kV Overloads	0
230 kV Overloads	17
138 kV Overloads	2
115 kV Overloads	6

Scenario 0D

Scenario Components

- LS Power: 2022-W3-548

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	21
500 kV Overloads	2
345 kV Overloads	2
230 kV Overloads	2
138 kV Overloads	11
115 kV Overloads	2

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	93
500 kV Overloads	17
345 kV Overloads	0
230 kV Overloads	38
138 kV Overloads	6
115 kV Overloads	21

Scenario 0E

Scenario Components

1A_ALL

- Exelon: 2022-W3-344/660
- FE: 2022-W3-837
- DOM: 2022-W3-711
- DOM/FE: 2022-W3-516/837
- DOM: 2022-W3-692

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	24
500 kV Overloads	0
345 kV Overloads	2
230 kV Overloads	1
138 kV Overloads	16
115 kV Overloads	3

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	57
500 kV Overloads	13
345 kV Overloads	0
230 kV Overloads	26
138 kV Overloads	4
115 kV Overloads	6

Scenario 0E1

Scenario Components

0E + PPL (374) + PSEG (637 component 5 and 8) → It will 0E +PPL (Otter to Conastone 500 kV) + PSEG (Conastone to Doubs 500 kV)

- Exelon: 2022-W3-344/660
- FE: 2022-W3-837
- DOM: 2022-W3-711
- DOM/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	22
500 kV Overloads	0
345 kV Overloads	2
230 kV Overloads	1
138 kV Overloads	15
115 kV Overloads	2

7,500 MW OSW Screening Performance

Overload	Number of Overloads
Total Overloads	57
500 kV Overloads	10
345 kV Overloads	0
230 kV Overloads	33
138 kV Overloads	3
115 kV Overloads	4

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	33
500 kV Overloads	3
345 kV Overloads	0
230 kV Overloads	19
138 kV Overloads	2
115 kV Overloads	4

11,000 MW OSW Screening Performance

Overload	Number of Overloads
Total Overloads	80
500 kV Overloads	15
345 kV Overloads	0
230 kV Overloads	41
138 kV Overloads	8
115 kV Overloads	5

Scenario 0E2

Scenario Components

0E + PSEG (229 component 8&9) → It will be 0E + PSEG (Hunterstown to Green Valley 500 kV)

- Exelon: 2022-W3-344/660
- FE: 2022-W3-837
- DOM: 2022-W3-711
- DOM/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- PSEG: 2022-W3-229 – only component 8&9

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	53
500 kV Overloads	16
345 kV Overloads	0
230 kV Overloads	27
138 kV Overloads	1
115 kV Overloads	3

Scenario 0E3

Scenario Components

0E Modified (500 kV Morrisville Start)

- Exelon: 2022-W3-344/660
- FE: 2022-W3-837
- DOM: 2022-W3-711 Modified
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	57
500 kV Overloads	13
345 kV Overloads	0
230 kV Overloads	27
138 kV Overloads	4
115 kV Overloads	6

Scenario 0E4

Scenario Components

0E1 + T-Point (loop Conastone-Brighton, Brighton-Doubs and Conastone-Doubs 500 kV)

- Exelon: 2022-W3-344/660
- FE: 2022-W3-837
- DOM: 2022-W3-711
- DOM/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- PPL: 2022-W3-374 – (Otter Creek-Conastone 500 kV)
- PSEG: 2022-W3-637 – only component 5&8 (Conastone-Doubs 500 kV new line)

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	35
500 kV Overloads	5
345 kV Overloads	0
230 kV Overloads	19
138 kV Overloads	2
115 kV Overloads	4

Scenario 0E4-1

Scenario Components

0E4 and bypass the Otter Creek-Conastone-T-Point at Conastone (the new line will be Otter Creek-T-Point 500 kV)

- Exelon: 2022-W3-344/660
- FE: 2022-W3-837
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- PPL: 2022-W3-374 –(Otter Creek-Conastone 500 kV)
- PSEG: 2022-W3-637 – only component 5&8 (Conastone-Doubs 500 kV new line)

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	34
500 kV Overloads	4
345 kV Overloads	0
230 kV Overloads	19
138 kV Overloads	2
115 kV Overloads	4

Scenario 0E4-1-1

Scenario Components

0E4-1 and replace Cooper-High Ridge 500 kV with Peach Bottom-Waugh Chapel 500 kV

- Exelon: 2022-W3-344/660 – Remove component 3&7 (Remove Cooper-High Ridge 500 kV and High Ridge 500/230 kV transformers)
- FE: 2022-W3-837
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- PPL: 2022-W3-374 –(Otter Creek-Conastone 500 kV)
- PSEG: 2022-W3-637 – only component 5&8 (Conastone-Doubs 500 kV new line)
- PSEG: 2022-W3-808 – Add Peach Bottom-Waugh Chapel 500 kV – exclude/bypass Raphael 500 kV bus

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	38
500 kV Overloads	5
345 kV Overloads	0
230 kV Overloads	22
138 kV Overloads	2
115 kV Overloads	4

Scenario 0E4-1-2

Scenario Components

0E4-1 and replace Cooper-High Ridge 500 kV with Peach Bottom-Brandon Shore 500 kV

- Exelon: 2022-W3-344/660 – Remove component 3&7 (Remove Cooper-High Ridge 500 kV and High Ridge 500/230 kV transformers)
- FE: 2022-W3-837
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- PPL: 2022-W3-374 –(Otter Creek-Conastone 500 kV)
- PSEG: 2022-W3-637 – only component 5&8 (Conastone-Doubs 500 kV new line)
- PSEG: 2022-W3-741 – Add Peach Bottom-Brandon Shore 500 kV

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	39
500 kV Overloads	6
345 kV Overloads	0
230 kV Overloads	21
138 kV Overloads	2
115 kV Overloads	5

Scenario 0E4-1-3

Scenario Components

0E4-1 and replace Cooper-High Ridge 500 kV with Keeney-Waugh 230 kV double circuit

- Exelon: 2022-W3-344/660 – Remove component 3&7 (Remove Cooper-High Ridge 500 kV and High Ridge 500/230 kV transformers)
- FE: 2022-W3-837
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- PPL: 2022-W3-374 (Otter Creek-Conastone 500 kV)
- PSEG: 2022-W3-637 – only component 5&8 (Conastone-Doubs 500 kV new line)
- NextEra: 2022-W3-948 – Add Keeney-Waugh 230 kV double circuit

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	39
500 kV Overloads	6
345 kV Overloads	0
230 kV Overloads	18
138 kV Overloads	3
115 kV Overloads	5

Scenario 0E5

Scenario Components

0E1 – FE 837 (component C18-30) + TRANSRC 487 (Component IEC-West)

- Exelon: 2022-W3-344/660
- FE: 2022-W3-837
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- PPL: 2022-W3-374 – (Otter Creek-Conastone 500 kV)
- PSEG: 2022-W3-637 – only component 5&8 (Conastone-Doubs 500 kV new line)
- Remove FE: 2022-W3-837 component C18-30_MAIT_Germantown-Carroll
- Add TRANSRC: 2022-W3-487 component IEC-West

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	33
500 kV Overloads	4
345 kV Overloads	0
230 kV Overloads	21
138 kV Overloads	1
115 kV Overloads	2

Scenario 0E6

Scenario Components

0E3 (500 kV Morrisville Start) - remove part of FE 837(Fort Martin-Doubs 500 kV) + Add Part of 977 (Yeat sub and Joshua-Yeat 765 kV line)

- Exelon: 2022-W3-344/660
- FE: 2022-W3-837 Modified (remove Fort Martin-Doubs 500 kV)
- DOM: 2022-W3-711 Modified
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- Transource: 2022-W3-977 (only add Yeat sub and Joshua-Yeat 765 kV line)

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	55
500 kV Overloads	11
345 kV Overloads	0
230 kV Overloads	23
138 kV Overloads	9
115 kV Overloads	6

Scenario 0E6-1

Scenario Components

0E6_Remove Prnty-Mt. Storm & Meadow Brook-Doubs

- Exelon: 2022-W3-344/660
- FE: 2022-W3-837 Modified (remove Fort Martin-Doubs 500 kV)
- DOM: 2022-W3-711 Modified
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- Transource: 2022-W3-977 (only add Yeat sub and Joshua-Yeat 765 kV line)

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	66
500 kV Overloads	11
345 kV Overloads	0
230 kV Overloads	23
138 kV Overloads	17
115 kV Overloads	7

Scenario 0E7

Scenario Components

0E6 - remove all FE 837

- Exelon: 2022-W3-344/660
- DOM: 2022-W3-711 Modified
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- Transource: 2022-W3-977 (only add Yeat sub and Joshua-Yeat 765 kV line)

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	75
500 kV Overloads	12
345 kV Overloads	0
230 kV Overloads	22
138 kV Overloads	20
115 kV Overloads	10

Scenario 0E8

Scenario Components

0E1 + Removal of remove Doubs-Fort Martin No. 1 500 kV & Pruntytown-Mt. Storm 500 kV & Meadowbrook-Doubs 500 kV lines and add Joshua Falls to Yeat 765 kV line

- Exelon: 2022-W3-344/660
- FE: 2022-W3-837 – Removal of Doubs-Fort Martin No. 1 500 kV & Pruntytown-Mt. Storm 500 kV & Meadowbrook-Doubs 500 kV line(s)
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8
- Transource: 2022-W3-904-Joshua Falls (AEP) to Yeat (Transource) 765 kV

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	40
500 kV Overloads	1
345 kV Overloads	0
230 kV Overloads	17
138 kV Overloads	11
115 kV Overloads	5

Scenario 0E8-1

Scenario Components

0E1 + Removal of remove Doubs-Fort Martin No. 1 500 kV & Pruntytown-Mt. Storm 500 kV & Meadowbrook-Doubs 500 kV lines and add Joshua Falls to Yeat 765 kV line + Removal of North Anna to Morrisville 500 kV line + Removal of Golden-Mars 500 kV line

- Exelon: 2022-W3-344/660
- FE: 2022-W3-837 – Removal of Doubs-Fort Martin No. 1 500 kV & Pruntytown-Mt. Storm 500 kV & Meadowbrook-Doubs 500 kV line(s)
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692 – Remove Golden-Mars 500 kV line
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8
- Transource: 2022-W3-904 – Joshua Falls (AEP) to Yeat (Transource) 765 kV

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	38
500 kV Overloads	1
345 kV Overloads	0
230 kV Overloads	15
138 kV Overloads	11
115 kV Overloads	5

Scenario 0E8-1-1

Scenario Components

0E8-1 + Remove Golden-Mars 230 kV side line

- Exelon: 2022-W3-344/660
- FE: 2022-W3-837 – Removal of Doubs-Fort Martin No. 1 500 kV & Pruntytown-Mt. Storm 500 kV & Meadowbrook-Doubs 500 kV line(s)
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692 – Remove Golden-Mars 500 kV line & Remove Golden-Mars 230 kV side line
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8
- Transource: 2022-W3-904 – Joshua Falls (AEP) to Yeat (Transource) 765 kV

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	39
500 kV Overloads	1
345 kV Overloads	0
230 kV Overloads	16
138 kV Overloads	11
115 kV Overloads	5

Scenario 0E8-2

Scenario Components

0E8-1 + Remove the rest of the FE837 + Add Transouce 487 (Component IEC-West only)

- Exelon: 2022-W3-344/660
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692 – Remove Golden-Mars 500 kV line
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8
- Transource: 2022-W3-904 – only Joshua Falls (AEP) to Yeat (Transource) 765 kV
- Transource: 2022-W3-487 (Component IEC-West only)

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	29
500 kV Overloads	1
345 kV Overloads	1
230 kV Overloads	2
138 kV Overloads	17
115 kV Overloads	2

7,500 MW OSW Screening Performance

Overload	Number of Overloads
Total Overloads	57
500 kV Overloads	9
345 kV Overloads	0
230 kV Overloads	31
138 kV Overloads	7
115 kV Overloads	2

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	31
500 kV Overloads	1
345 kV Overloads	0
230 kV Overloads	16
138 kV Overloads	6
115 kV Overloads	2

11,000 MW OSW Screening Performance

Overload	Number of Overloads
Total Overloads	75
500 kV Overloads	12
345 kV Overloads	0
230 kV Overloads	38
138 kV Overloads	11
115 kV Overloads	2

Scenario 0E8-2-1

Scenario Components

0E8-2 + Remove Golden-Mars 230 kV side line

- Exelon: 2022-W3-344/660
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692 – Remove Golden-Mars 500 kV line & Remove Golden-Mars 230 kV side line
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8
- Transource: 2022-W3-904 – only Joshua Falls (AEP) to Yeat (Transource) 765 kV
- Transource: 2022-W3-487 (Component IEC-West only)

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	32
500 kV Overloads	1
345 kV Overloads	0
230 kV Overloads	17
138 kV Overloads	6
115 kV Overloads	2

Scenario 0E8-2-2

Scenario Components

0E8-2-1 + Remove uprate on 500 kV Line Meadow Brook-Vint Hill

- Exelon: 2022-W3-344/660
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line + Remove uprate on 500 kV Line Meadow Brook-Vint Hill
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692 – Remove Golden-Mars 500 kV line
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8
- Transource: 2022-W3-904 – only Joshua Falls (AEP) to Yeat (Transource) 765 kV
- Transource: 2022-W3-487 (Component IEC-West only)

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	32
500 kV Overloads	1
345 kV Overloads	0
230 kV Overloads	17
138 kV Overloads	6
115 kV Overloads	2

Scenario 0E9

Scenario Components

0E1 + Modified DOM_711 (500 kV Morrisville Start) + Modified DOM_692 (Remove Golden-2-Mars Extension)

- Exelon: 2022-W3-344/660
- FE: 2022-W3-837
- DOM: 2022-W3-711 Modified (500 kV Morrisville Start)
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692 Modified (Remove Golden-2-Mars Extension)
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	35
500 kV Overloads	3
345 kV Overloads	0
230 kV Overloads	20
138 kV Overloads	2
115 kV Overloads	5

Scenario 0E10

Scenario Components

0E1 modified (the Otter Creek-Conastone-Doubs 500 kV circuit will bypass the Conastone station and will be Otter Creek-Doubs 500 kV)

- Exelon: 2022-W3-344/660
- FE: 2022-W3-837
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	37
500 kV Overloads	4
345 kV Overloads	0
230 kV Overloads	21
138 kV Overloads	2
115 kV Overloads	5

Scenario 0E11

Scenario Components

0E1 + Removal of remove Doubs-Fort Martin No. 1 500 kV line

- Exelon: 2022-W3-344/660
- FE: 2022-W3-837 – Removal of Doubs-Fort Martin No. 1 500 kV line
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	46
500 kV Overloads	4
345 kV Overloads	0
230 kV Overloads	23
138 kV Overloads	7
115 kV Overloads	5

Scenario 0E11-1

Scenario Components

0E1 + Removal of remove Doubs-Fort Martin No. 1 500 kV line + Removal of North Anna to Morrisville 500 kV line+ Removal of Golden-Mars 500 kV line

- Exelon: 2022-W3-344/660
- FE: 2022-W3-837 – Removal of Doubs-Fort Martin No. 1 500 kV line
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692 – Remove Golden-Mars 500 kV line
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	45
500 kV Overloads	4
345 kV Overloads	0
230 kV Overloads	23
138 kV Overloads	7
115 kV Overloads	5

Scenario 0E11-1-1

Scenario Components

0E11-1 + Remove Golden-Mars 230 kV side line

- Exelon: 2022-W3-344/660
- FE: 2022-W3-837 – Removal of Doubs-Fort Martin No. 1 500 kV line
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692 – Remove Golden-Mars 500 kV line & Remove Golden-Mars 230 kV side line
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	46
500 kV Overloads	4
345 kV Overloads	0
230 kV Overloads	24
138 kV Overloads	7
115 kV Overloads	5

Scenario 0E11-2

Scenario Components

0E11-1-1 + Remove Pruntytown to Mt.Storm and Meadow Brook to Doubs 500 kV line & Add Fort Martin to Doubs 500 kV line

- Exelon: 2022-W3-344/660
- FE: 2022-W3-837 – Remove Pruntytown to Mt.Storm and Meadow Brook to Doubs 500 kV lines, Add Fort Martin to Doubs 500 kV line
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692 – Remove Golden-Mars 500 kV line & Remove Golden-Mars 230 kV side line
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	38
500 kV Overloads	6
345 kV Overloads	0
230 kV Overloads	19
138 kV Overloads	3
115 kV Overloads	5

Scenario 0E11-3

Scenario Components

0E11-1-1 + Remove all FE 2022-W3 -837 + Add NextEra 2022-W3-853

- Exelon: 2022-W3-344/660
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692 – Remove Golden-Mars 500 kV line & Remove Golden-Mars 230 kV side line
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8
- NextEra: 2022-W3-853

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	37
500 kV Overloads	2
345 kV Overloads	0
230 kV Overloads	19
138 kV Overloads	4
115 kV Overloads	7

Scenario 0E11-4

Scenario Components

0E11-3 + Add Joshua Falls-Yeat 765 kV line

- Exelon: 2022-W3-344/660
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692 – Remove Golden-Mars 500 kV line & Remove Golden-Mars 230 kV side line
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8
- NextEra: 2022-W3-853
- Transource: 2022-W3-904 – only Joshua Falls (AEP) to Yeat (Transource) 765 kV & Yeat 765/500 kV substation

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	31
500 kV Overloads	1
345 kV Overloads	0
230 kV Overloads	14
138 kV Overloads	7
115 kV Overloads	5

Scenario 0E11-5

Scenario Components

0E11-4 + Remove uprate on 500 kV Line Meadow Brook-Vint Hill

- Exelon: 2022-W3-344/660
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line + Remove uprate on 500 kV Line Meadow Brook-Vint Hill
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692 – Remove Golden-Mars 500 kV line & Remove Golden-Mars 230 kV side line
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8
- NextEra: 2022-W3-853
- Transource: 2022-W3-904 – only Joshua Falls (AEP) to Yeat (Transource) 765 kV & Yeat 765/500 kV substation

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	31
500 kV Overloads	1
345 kV Overloads	0
230 kV Overloads	14
138 kV Overloads	7
115 kV Overloads	5

Scenario 0E11-6

Scenario Components

0E11-3 + Remove Otter Creek-Conastone-Doubs 500 kV

- Exelon: 2022-W3-344/660
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692 – Remove Golden-Mars 500 kV line & Remove Golden-Mars 230 kV side line
- NextEra: 2022-W3-853

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	60
500 kV Overloads	11
345 kV Overloads	0
230 kV Overloads	27
138 kV Overloads	7
115 kV Overloads	9

Scenario 0E11-7

Scenario Components

0E11-3+ (bypass Conastone for the Otter Creek-Doubs line) +/- reactive

- Exelon: 2022-W3-344/660 (remove the 500 kV cap banks at Gracetone and Conastone)
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line + Remove uprate on 500 kV Line Meadow Brook-Vint Hill
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692 – Remove Golden-Mars 500 kV line & Remove Golden-Mars 230 kV side line
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8 – bypass Conastone
- NextEra: 2022-W3-853
- DOM: 2022-W3-231 (only include the components below)
- 150 MVARs at Morrsivlle 500 kV,
- 293 MVARs at Wishing Star 500 kV
- 150 MVARs at Mars 230 kV
- 150 MVARs at Wishing Star 230 kV
- 300 MVARs STATCOM at Mars 500 kV
- 300 MVARs STATCOM at Beaumeade 230 kV
- Granite Statcom: +/- 350 MVar

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	33
500 kV Overloads	1
345 kV Overloads	0
230 kV Overloads	18
138 kV Overloads	3
115 kV Overloads	6

Scenario 0E11-7-A

Scenario Components

0E11-7 with full proposal 692 modeled

- Exelon: 2022-W3-344/660 (remove the 500 kV cap banks at Gracetone and Conastone)
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line + Remove uprate on 500 kV Line Meadow Brook-Vint Hill
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8 – bypass Conastone
- NextEra: 2022-W3-853
- DOM: 2022-W3-231 (only include the components below)
- 150 MVARs at Morrsivlle 500 kV,
- 293 MVARs at Wishing Star 500 kV
- 150 MVARs at Mars 230 kV
- 150 MVARs at Wishing Star 230 kV
- 300 MVARs STATCOM at Mars 500 kV
- 300 MVARs STATCOM at Beaumeade 230 kV
- Granite Statcom: +/- 350 MVar

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	33
500 kV Overloads	1
345 kV Overloads	0
230 kV Overloads	18
138 kV Overloads	3
115 kV Overloads	6

Scenario 0E11-7-B

Scenario Components

0E11-7-A + bypass Black Oak + AEP 410 (cloverdale breaker) + DOM additional_Post Fixes

- Exelon: 2022-W3-344/660 (remove the 500 kV cap banks at Gracetone and Conastone)
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line + Remove uprate on 500 kV Line Meadow Brook-Vint Hill
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8 – bypass Conastone
- NextEra: 2022-W3-853 (Bypass Black Oak)
- DOM: 2022-W3-231 (only include the components below)
- 150 MVARs at Morrsivlle 500 kV,
- 293 MVARs at Wishing Star 500 kV
- 150 MVARs at Mars 230 kV
- 150 MVARs at Wishing Star 230 kV
- 300 MVARs STATCOM at Mars 500 kV
- 300 MVARs STATCOM at Beaumeade 230 kV
- Granite Statcom: +/- 350 MVar
- AEP: 2022-W3-410
- DOM Additional:
- 2022-W3-30: Line No. 2054 (Charlottesville to Hollymead) Rebuild (Option 1) (exclude DNH portion for now)
- 2022-W3-704: Line No. 2135 (Holly Meade to Gordonsville) Rebuild (Option 1)
- 2022-W3-731: Locks Substation 230/115 kV Transformer Upgrade
- 2022-W3-74: Line No. 2090 (Ladysmith to Fredericksburg) Rebuild
- Post Fixes:
  - Line No. 256 Rebuild St. Johns-Ladysmith CT
  - Sterling Park-Golden
  - Davis Drive-Sterling Park

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	26
500 kV Overloads	2
345 kV Overloads	0
230 kV Overloads	12
138 kV Overloads	3
115 kV Overloads	6

2030 Screening Performance

Overload	Number of Overloads
Total Overloads	60
500 kV Overloads	12
345 kV Overloads	0
230 kV Overloads	22
138 kV Overloads	11
115 kV Overloads	9

Scenario 0E11-7-B + Yeat

Scenario Components

0E11-7-B + YEAT 765 kV line

- Exelon: 2022-W3-344/660 (remove the 500 kV cap banks at Gracetone and Conastone)
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line + Remove uprate on 500 kV Line Meadow Brook-Vint Hill
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8 – bypass Conastone
- NextEra: 2022-W3-853 (Bypass Black Oak)
- Transource: 2022-W3-904 (only include Yeat sub and Joshua Falls-Yeat 765 kV line)
- DOM: 2022-W3-231 (only include the components below)
- 150 MVARs at Morrsivlle 500 kV,
- 293 MVARs at Wishing Star 500 kV
- 150 MVARs at Mars 230 kV
- 150 MVARs at Wishing Star 230 kV
- 300 MVARs STATCOM at Mars 500 kV
- 300 MVARs STATCOM at Beaumeade 230 kV
- Granite Statcom: +/- 350 MVar
- AEP: 2022-W3-410
- DOM Additional:
- 2022-W3-30: Line No. 2054 (Charlottesville to Hollymead) Rebuild (Option 1) (exclude DNH portion for now)
- 2022-W3-704: Line No. 2135 (Holly Meade to Gordonsville) Rebuild (Option 1)
- 2022-W3-731: Locks Substation 230/115 kV Transformer Upgrade
- 2022-W3-74: Line No. 2090 (Ladysmith to Fredericksburg) Rebuild
- Post Fixes:
  - Line No. 256 Rebuild St. Johns-Ladysmith CT
  - Sterling Park-Golden
  - Davis Drive-Sterling Park

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	25
500 kV Overloads	2
345 kV Overloads	0
230 kV Overloads	9
138 kV Overloads	6
115 kV Overloads	5

2030 Screening Performance

Overload	Number of Overloads
Total Overloads	50
500 kV Overloads	9
345 kV Overloads	0
230 kV Overloads	15
138 kV Overloads	12
115 kV Overloads	7

Scenario 0E11-7-B + IEC West

Scenario Components

0E11-7-B + IEC West

- Exelon: 2022-W3-344/660 (remove the 500 kV cap banks at Gracetone and Conastone)
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line + Remove uprate on 500 kV Line Meadow Brook-Vint Hill
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8 – bypass Conastone
- NextEra: 2022-W3-853 (Bypass Black Oak)
- Transource: 2022-W3-487(only include IEC West)
- DOM: 2022-W3-231 (only include the components below)
- 150 MVARs at Morrsivlle 500 kV,
- 293 MVARs at Wishing Star 500 kV
- 150 MVARs at Mars 230 kV
- 150 MVARs at Wishing Star 230 kV
- 300 MVARs STATCOM at Mars 500 kV
- 300 MVARs STATCOM at Beaumeade 230 kV
- Granite Statcom: +/- 350 MVar
- AEP: 2022-W3-410
- DOM Additional:
- 2022-W3-30: Line No. 2054 (Charlottesville to Hollymead) Rebuild (Option 1) (exclude DNH portion for now)
- 2022-W3-704: Line No. 2135 (Holly Meade to Gordonsville) Rebuild (Option 1)
- 2022-W3-731: Locks Substation 230/115 kV Transformer Upgrade
- 2022-W3-74: Line No. 2090 (Ladysmith to Fredericksburg) Rebuild
- Post Fixes:
  - Line No. 256 Rebuild St. Johns-Ladysmith CT
  - Sterling Park-Golden
  - Davis Drive-Sterling Park

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	21
500 kV Overloads	2
345 kV Overloads	0
230 kV Overloads	14
138 kV Overloads	0
115 kV Overloads	2

Scenario 0E11-7-B + Hunterstown-Carrol Rebuild

Scenario Components

0E11-7-B + Hunterstown -Carrol Rebuild

- Exelon: 2022-W3-344/660 (remove the 500 kV cap banks at Gracetone and Conastone)
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line + Remove uprate on 500 kV Line Meadow Brook-Vint Hill
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8 – bypass Conastone
- NextEra: 2022-W3-853 (Bypass Black Oak)
- FE: 2022-W3-837 (only include Hunterstown-Carrol Rebuild (C18-30), but UPDATED idv from FE)
- DOM: 2022-W3-231 (only include the components below)
- 150 MVARs at Morrsivlle 500 kV,
- 293 MVARs at Wishing Star 500 kV
- 150 MVARs at Mars 230 kV
- 150 MVARs at Wishing Star 230 kV
- 300 MVARs STATCOM at Mars 500 kV
- 300 MVARs STATCOM at Beaumeade 230 kV
- Granite Statcom: +/- 350 MVar
- AEP: 2022-W3-410
- DOM Additional:
- 2022-W3-30: Line No. 2054 (Charlottesville to Hollymead) Rebuild (Option 1) (exclude DNH portion for now)
- 2022-W3-704: Line No. 2135 (Holly Meade to Gordonsville) Rebuild (Option 1)
- 2022-W3-731: Locks Substation 230/115 kV Transformer Upgrade
- 2022-W3-74: Line No. 2090 (Ladysmith to Fredericksburg) Rebuild
- Post Fixes:
  - Line No. 256 Rebuild St. Johns-Ladysmith CT
  - Sterling Park-Golden
  - Davis Drive-Sterling Park

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	**25**
500 kV Overloads	**1**
345 kV Overloads	**0**
230 kV Overloads	**16**
138 kV Overloads	**2**
115 kV Overloads	**3**

Scenario 0E11-7-B + Hunterstown-Carrol Rebuild + IEC West

Scenario Components

0E11-7-B + Hunterstown-Carrol Rebuild + IEC West

- Exelon: 2022-W3-344/660 (remove the 500 kV cap banks at Gracetone and Conastone)
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line + Remove uprate on 500 kV Line Meadow Brook-Vint Hill
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8 – bypass Conastone
- NextEra: 2022-W3-853 (Bypass Black Oak)
- Transource: 2022-W3-487(only include IEC West)
- FE: 2022-W3-837 (only include Hunterstown-Carrol Rebuild (C18-30) – the idv in the proposal was wrong, use updated idvs PJM sent later)
- DOM: 2022-W3-231 (only include the components below)
- 150 MVARs at Morrsivlle 500 kV,
- 293 MVARs at Wishing Star 500 kV
- 150 MVARs at Mars 230 kV
- 150 MVARs at Wishing Star 230 kV
- 300 MVARs STATCOM at Mars 500 kV
- 300 MVARs STATCOM at Beaumeade 230 kV
- Granite Statcom: +/- 350 MVar
- AEP: 2022-W3-410
- DOM Additional:
- 2022-W3-30: Line No. 2054 (Charlottesville to Hollymead) Rebuild (Option 1) (exclude DNH portion for now)
- 2022-W3-704: Line No. 2135 (Holly Meade to Gordonsville) Rebuild (Option 1)
- 2022-W3-731: Locks Substation 230/115 kV Transformer Upgrade
- 2022-W3-74: Line No. 2090 (Ladysmith to Fredericksburg) Rebuild
- Post Fixes:
  - Line No. 256 Rebuild St. Johns-Ladysmith CT
  - Sterling Park-Golden
  - Davis Drive-Sterling Park

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	22
500 kV Overloads	2
345 kV Overloads	0
230 kV Overloads	15
138 kV Overloads	0
115 kV Overloads	2

Scenario 0E11-7-B Final

Scenario Components

- Exelon: 2022-W3-344/660
- DOM: 2022-W3-711 (Remove North Anna to Morrisville 500 kV line)
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- PPL: 2022-W3-374 and PSEG: 2022-W3-637 (only component 5&8) – Bypass Conastone
- NextEra: 2022-W3-853 (bypass Black Oak, end at Aspen)
- DOM: 2022-W3-231 (Partial)
- 150 MVARs at Morrsivlle 500 kV,
- 293 MVARs at Wishing Star 500 kV
- 150 MVARs at Mars 230 kV
- 150 MVARs at Wishing Star 230 kV
- 300 MVARs STATCOM at Mars 500 kV
- 300 MVARs STATCOM at Beaumeade 230 kV
- Granite Statcom
- AEP: 2022-W3-410
- FE: 2022-W3-837 (Partial): Hunterstown-Carrol rebuild (use the updated idv PJM sent later)
- DOM: 2022-W3-731
- DOM: 2022-W3-211
- DOM: 2022-W3-967 (Partial)
- Entire Line No. 2054 (Charlottesville to Hollymead) Rebuild, Entire Line No. 291 Rebuild and Portion of Line No. 233 rebuild
- 230 kV Line No. 2054
- 6CHARLVL (314749) – 6PROFFIT (314772) ckt 1
- 230 kV Line No. 233
- 6BARRCK2 (314742) – 6CROZET1 (314751) ckt 1
- 230 kV Line No. 291
- 6CROZET2 (314752) – 6DOOMS (314794) ckt 1
- 6BARRCK1 (314741) – 6CROZET2 (314752) ckt 1
- 6BARRCK1 (314741) – 6CHARLVL (314749) ckt 1
- DOM: 2022-W3-74 (Partial)
- 6SUMMIT (313837) – 6LDYSMITH CT (314197) ckt 1
- Sterling Park-Golden Rebuild ($7.97M)
- Davis Drive-Sterling Park Rebuild ($5.5M)
- Red Lion-Hope Creek 500 kV line terminal equipment upgrade
- Peach Bottom terminal equipment upgrades
- Carrol-Mt Airy 230 kV Terminal Equipment upgrades
- Reconductor the Lincoln-Orrtanna 115 kV line
- FAYETT-GRANDP 138 kV line terminal equipment upgrades

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	21
500 kV Overloads	1
345 kV Overloads	0
230 kV Overloads	13
138 kV Overloads	1
115 kV Overloads	2

Scenario 0E11-8

Scenario Components

0E11-7+ IEC West (Transource 487)

- Exelon: 2022-W3-344/660 (remove the 500 kV cap banks at Gracetone and Conastone)
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line + Remove uprate on 500 kV Line Meadow Brook-Vint Hill
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692 – Remove Golden-Mars 500 kV line & Remove Golden-Mars 230 kV side line
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8 – bypass Conastone
- NextEra: 2022-W3-853
- DOM: 2022-W3-231 (only include the components below)
- 150 MVARs at Morrsivlle 500 kV,
- 293 MVARs at Wishing Star 500 kV
- 150 MVARs at Mars 230 kV
- 150 MVARs at Wishing Star 230 kV
- 300 MVARs STATCOM at Mars 500 kV
- 300 MVARs STATCOM at Beaumeade 230 kV
- Granite Statcom: +/- 350 MVar
- Transourse: 2022-W3-487 (Only include the IEC West)

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	**31**
500 kV Overloads	**1**
345 kV Overloads	**0**
230 kV Overloads	**22**
138 kV Overloads	**1**
115 kV Overloads	**2**

Scenario 0E11-9

Scenario Components

0E11-7+ Modified West line (part of 853 + Part of 548)

- Exelon: 2022-W3-344/660 (remove the 500 kV cap banks at Gracetone and Conastone)
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line + Remove uprate on 500 kV Line Meadow Brook-Vint Hill
- Dom/FE: 2022-W3-516/837
- LS Power: 2022-W3-548 (only include 502 J- Black Oak-Doubs 500 kV line but bypass Black Oak), connect with the Doubs-Apsen 500 kV line in 516 and bypass Doubs
- DOM: 2022-W3-692 – Remove Golden-Mars 500 kV line & Remove Golden-Mars 230 kV side line
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8 – bypass Conastone
- NextEra: 2022-W3-853 (Only include Stonewall tap-Belmont tap 500 kV line, including the Stonewall and Belmont sub)
- DOM: 2022-W3-231 (only include the components below)
- 150 MVARs at Morrsivlle 500 kV,
- 293 MVARs at Wishing Star 500 kV
- 150 MVARs at Mars 230 kV
- 150 MVARs at Wishing Star 230 kV
- 300 MVARs STATCOM at Mars 500 kV
- 300 MVARs STATCOM at Beaumeade 230 kV
- Granite Statcom: +/- 350 MVar

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	36
500 kV Overloads	2
345 kV Overloads	0
230 kV Overloads	20
138 kV Overloads	3
115 kV Overloads	6

Scenario 0E11-10

Scenario Components

0E11-7+ Replace the NEET 853 with Transource 765 kV line

- Exelon: 2022-W3-344/660 (remove the 500 kV cap banks at Gracetone and Conastone)
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line + Remove uprate on 500 kV Line Meadow Brook-Vint Hill
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692 – Remove Golden-Mars 500 kV line & Remove Golden-Mars 230 kV side line
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8 – bypass Conastone
- FE: 2022-W3-837 (Only include Bedington SVC, no lines)
- Transource: 2022-W3-904 (only include Yeat sub and Joshua Falls-Yeat 765 kV line)
- DOM: 2022-W3-231 (only include the components below)
- 150 MVARs at Morrsivlle 500 kV,
- 293 MVARs at Wishing Star 500 kV
- 150 MVARs at Mars 230 kV
- 150 MVARs at Wishing Star 230 kV
- 300 MVARs STATCOM at Mars 500 kV
- 300 MVARs STATCOM at Beaumeade 230 kV
- Granite Statcom: +/- 350 MVar (part of Brandon Shores deactivation)
- AEP: AEP: 2022-W3-410

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	42
500 kV Overloads	3
345 kV Overloads	0
230 kV Overloads	13
138 kV Overloads	13
115 kV Overloads	7

Scenario 0E11-10-A

Scenario Components

0E11-10 with full proposal 692 modeled

- Exelon: 2022-W3-344/660 (remove the 500 kV cap banks at Gracetone and Conastone)
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line + Remove uprate on 500 kV Line Meadow Brook-Vint Hill
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8 – bypass Conastone
- FE: 2022-W3-837 (Only include Bedington SVC, no lines)
- Transource: 2022-W3-904 (only include Yeat sub and Joshua Falls-Yeat 765 kV line)
- DOM: 2022-W3-231 (only include the components below)
- 150 MVARs at Morrsivlle 500 kV,
- 293 MVARs at Wishing Star 500 kV
- 150 MVARs at Mars 230 kV
- 150 MVARs at Wishing Star 230 kV
- 300 MVARs STATCOM at Mars 500 kV
- 300 MVARs STATCOM at Beaumeade 230 kV
- Granite Statcom: +/- 350 MVar (part of Brandon Shores deactivation)
- AEP: AEP: 2022-W3-410

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	42
500 kV Overloads	3
345 kV Overloads	0
230 kV Overloads	13
138 kV Overloads	13
115 kV Overloads	7

Scenario 0E11-11

Scenario Components

0E10 + IEC West (Transource 487)

- Exelon: 2022-W3-344/660 (remove the 500 kV cap banks at Gracetone and Conastone)
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line + Remove uprate on 500 kV Line Meadow Brook-Vint Hill
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692 – Remove Golden-Mars 500 kV line & Remove Golden-Mars 230 kV side line
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8 – bypass Conastone
- FE: 2022-W3-837 (Only include Bedington SVC, no lines)
- Transource: 2022-W3-904 (only include Yeat sub and Joshua Falls-Yeat 765 kV line)
- DOM: 2022-W3-231 (only include the components below)
- 150 MVARs at Morrsivlle 500 kV,
- 293 MVARs at Wishing Star 500 kV
- 150 MVARs at Mars 230 kV
- 150 MVARs at Wishing Star 230 kV
- 300 MVARs STATCOM at Mars 500 kV
- 300 MVARs STATCOM at Beaumeade 230 kV
- Granite Statcom: +/- 350 MVar (part of Brandon Shores deactivation)
- AEP: AEP: 2022-W3-410
- Transource: 2022-W3-487 (IEC West Only)

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	**34**
500 kV Overloads	**2**
345 kV Overloads	**0**
230 kV Overloads	**18**
138 kV Overloads	**6**
115 kV Overloads	**2**

Scenario 0E11-12

Scenario Components

0E11-7 + Remove 853 + Add 279

- Exelon: 2022-W3-344/660 (remove the 500 kV cap banks at Gracetone and Conastone)
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line + Remove uprate on 500 kV Line Meadow Brook-Vint Hill
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692 – Remove Golden-Mars 500 kV line & Remove Golden-Mars 230 kV side line
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8 – bypass Conastone
- NextEra: 2022-W3-279
- DOM: 2022-W3-231 (only include the components below)
- 150 MVARs at Morrsivlle 500 kV,
- 293 MVARs at Wishing Star 500 kV
- 150 MVARs at Mars 230 kV
- 150 MVARs at Wishing Star 230 kV
- 300 MVARs STATCOM at Mars 500 kV
- 300 MVARs STATCOM at Beaumeade 230 kV
- Granite Statcom: +/- 350 MVar

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	42
500 kV Overloads	5
345 kV Overloads	0
230 kV Overloads	18
138 kV Overloads	8
115 kV Overloads	6

Scenario 0E12

Scenario Components

(0E1 + Addition of one additional 500 kV line between Doubs and Aspen + Remove Golden-Mars 500 kV + Remove North Anna-Morrisville 500 kV) or (0E9 + Additional one 500 kV line from Doubs to Aspen)

- Exelon: 2022-W3-344/660
- FE: 2022-W3-837
- DOM: 2022-W3-711 – Remove North Anna-Morrisville 500 kV line
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692 – Remove Golden-March 500 kV line
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8
- Additional one 500 kV line from Doubs to Aspen

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	33
500 kV Overloads	2
345 kV Overloads	0
230 kV Overloads	20
138 kV Overloads	2
115 kV Overloads	4

Scenario 0E13

Scenario Components

0E1 + Remove Exelon 344 component 4&5 + add PSEG 808 (Peach Bottom-Raphael-W. Chapel 500 kV)

- Exelon: 2022-W3-344/660 – Remove component 4&5
- FE: 2022-W3-837
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8
- PSEG: 2022-W3-808 – add the Peach Bottom-Raphael Rd-W. chapel 500 kV component

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	30
500 kV Overloads	4
345 kV Overloads	0
230 kV Overloads	17
138 kV Overloads	1
115 kV Overloads	4

Scenario 0E13-1

Scenario Components

0E13 + Remove Graceton 500/230 kV transformers

- Exelon: 2022-W3-344/660 – Remove component 4&5 and Graceton 500/230 kV transformers
- FE: 2022-W3-837
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8
- PSEG: 2022-W3-808 – add the Peach Bottom-Raphael Rd-W. chapel 500 kV component

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	32
500 kV Overloads	4
345 kV Overloads	0
230 kV Overloads	19
138 kV Overloads	1
115 kV Overloads	4

Scenario 0F

Scenario Components

1A-Alter_ALL

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/23
- DOM: 2022-W3-692

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	22
500 kV Overloads	1
345 kV Overloads	2
230 kV Overloads	1
138 kV Overloads	13
115 kV Overloads	3

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	55
500 kV Overloads	13
345 kV Overloads	0
230 kV Overloads	25
138 kV Overloads	4
115 kV Overloads	5

Scenario 0G

Scenario Components

1A-Alter_ALL (Full DOM proposals)

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/23
- DOM: 2022-W3-692
- DOM: 2022-W3-923
- DOM: 2022-W3-671
- DOM: 2022-W3-731
- DOM: 2022-W3-704
- DOM: 2022-W3-211
- DOM: 2022-W3-30
- DOM: 2022-W3-967
- DOM: 2022-W3-74

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	18
500 kV Overloads	1
345 kV Overloads	2
230 kV Overloads	0
138 kV Overloads	11
115 kV Overloads	3

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	50
500 kV Overloads	13
345 kV Overloads	0
230 kV Overloads	22
138 kV Overloads	3
115 kV Overloads	5

Scenario 0H

Scenario Components

1A-Alter_ALL (Full DOM proposals) _Hunterstown-Doubs-Goose Creek

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/23
- DOM: 2022-W3-692
- DOM: 2022-W3-923
- DOM: 2022-W3-671
- DOM: 2022-W3-731
- DOM: 2022-W3-704
- DOM: 2022-W3-211
- DOM: 2022-W3-30
- DOM: 2022-W3-967
- DOM: 2022-W3-74
- NEET: part of 2022-W3-445 (Hunterstown-Doubs-Goose Creek 500 kV part)

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	15
500 kV Overloads	1
345 kV Overloads	2
230 kV Overloads	0
138 kV Overloads	9
115 kV Overloads	2

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	44
500 kV Overloads	14
345 kV Overloads	0
230 kV Overloads	21
138 kV Overloads	1
115 kV Overloads	2

Scenario 0H2

Scenario Components

0G (1A-Alter_ALL (Full DOM proposals) _Hunterstown-Doubs-Goose Creek) + Remove Fort Martin-Doubs ckt 2 and Hunterstown-Carroll 230 kV line

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23 (Remove Fort Martin-Doubs ckt 2 and Hunterstown-Carroll 230 kV line)
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/23
- DOM: 2022-W3-692
- DOM: 2022-W3-923
- DOM: 2022-W3-671
- DOM: 2022-W3-731
- DOM: 2022-W3-704
- DOM: 2022-W3-211
- DOM: 2022-W3-30
- DOM: 2022-W3-967
- DOM: 2022-W3-74
- NEET: part of 2022-W3-445 (Hunterstown-Doubs-Goose Creek 500 kV part)

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	45
500 kV Overloads	14
345 kV Overloads	0
230 kV Overloads	19
138 kV Overloads	3
115 kV Overloads	5

Scenario 0I

Scenario Components

1A-Alter_ALL (Full DOM proposals) _T-Point substation

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/23
- DOM: 2022-W3-692
- DOM: 2022-W3-923
- DOM: 2022-W3-671
- DOM: 2022-W3-731
- DOM: 2022-W3-704
- DOM: 2022-W3-211
- DOM: 2022-W3-30
- DOM: 2022-W3-967
- DOM: 2022-W3-74
- NEET: Part of 2022-W3-948 (T-Point sub, just the Tap, no lines)

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	21
500 kV Overloads	1
345 kV Overloads	2
230 kV Overloads	0
138 kV Overloads	14
115 kV Overloads	3

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	47
500 kV Overloads	14
345 kV Overloads	0
230 kV Overloads	19
138 kV Overloads	2
115 kV Overloads	5

Scenario 0J

Scenario Components

1A-Alter_ALL (Full DOM proposals) _T-Point substation + two T-Point-Doubs or Goose Creek 230 kV lines

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/23
- DOM: 2022-W3-692
- DOM: 2022-W3-923
- DOM: 2022-W3-671
- DOM: 2022-W3-731
- DOM: 2022-W3-704
- DOM: 2022-W3-211
- DOM: 2022-W3-30
- DOM: 2022-W3-967
- DOM: 2022-W3-74
- NEET: Part of 2022-W3-948 (T-Point sub, just the Tap, two 230 kV line from T- Point-Doubs or Goose Creek)

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	21
500 kV Overloads	1
345 kV Overloads	2
230 kV Overloads	1
138 kV Overloads	13
115 kV Overloads	3

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	49
500 kV Overloads	16
345 kV Overloads	0
230 kV Overloads	20
138 kV Overloads	2
115 kV Overloads	5

Scenario 0J-2

Scenario Components

1A-Alter_ALL (Full DOM proposals) _T-Point substation + T-Point-Doubs 500 kV lines

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/23
- DOM: 2022-W3-692
- DOM: 2022-W3-923
- DOM: 2022-W3-671
- DOM: 2022-W3-731
- DOM: 2022-W3-704
- DOM: 2022-W3-211
- DOM: 2022-W3-30
- DOM: 2022-W3-967
- DOM: 2022-W3-74
- NEET: Part of 2022-W3-948 (T-Point sub, just the Tap, T- Point-Doubs 500 kV line)

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	21
500 kV Overloads	1
345 kV Overloads	2
230 kV Overloads	0
138 kV Overloads	14
115 kV Overloads	3

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	48
500 kV Overloads	17
345 kV Overloads	0
230 kV Overloads	18
138 kV Overloads	2
115 kV Overloads	5

Scenario 0J-3

Scenario Components

1A-Alter_ALL (Full DOM proposals) _ 0J-2 with REMOVING West Cooper-High Ridge 500 kV line

- Exelon: 2022-W3-344/660 (Remove West Cooper-High Ridge 500 kV line)
- FE: 2022-W3-23
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/23
- DOM: 2022-W3-692
- DOM: 2022-W3-923
- DOM: 2022-W3-671
- DOM: 2022-W3-731
- DOM: 2022-W3-704
- DOM: 2022-W3-211
- DOM: 2022-W3-30
- DOM: 2022-W3-967
- DOM: 2022-W3-74
- NEET: Part of 2022-W3-948 (T-Point sub, just the Tap) + T- Point-Doubs 500 kV line

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	25
500 kV Overloads	2
345 kV Overloads	2
230 kV Overloads	1
138 kV Overloads	14
115 kV Overloads	4

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	82
500 kV Overloads	17
345 kV Overloads	0
230 kV Overloads	29
138 kV Overloads	6
115 kV Overloads	16

Scenario 0K

Scenario Components

1A-Alter_ALL (Full DOM proposals) _ Conastone-Doubs 500 kV line

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/23
- DOM: 2022-W3-692
- DOM: 2022-W3-923
- DOM: 2022-W3-671
- DOM: 2022-W3-731
- DOM: 2022-W3-704
- DOM: 2022-W3-211
- DOM: 2022-W3-30
- DOM: 2022-W3-967
- DOM: 2022-W3-74
- PSEG: Part of 2022-W3-637 (Conastone-Doubs 500 kV line)

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	19
500 kV Overloads	1
345 kV Overloads	2
230 kV Overloads	0
138 kV Overloads	12
115 kV Overloads	3

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	45
500 kV Overloads	16
345 kV Overloads	0
230 kV Overloads	18
138 kV Overloads	1
115 kV Overloads	4

Scenario 0L

Scenario Components

1A-Alter_ALL (Full DOM proposals)

- Exelon: 2022-W3-344/660
- FE: 2022-W3-837 (not include Meadow Brook-Doubs line)
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/23
- DOM: 2022-W3-692
- DOM: 2022-W3-923
- DOM: 2022-W3-671
- DOM: 2022-W3-731
- DOM: 2022-W3-704
- DOM: 2022-W3-211
- DOM: 2022-W3-30
- DOM: 2022-W3-967
- DOM: 2022-W3-74
- NEET: 663 (Add Front Royal-New Wishing Star 500 kV line)

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	20
500 kV Overloads	1
345 kV Overloads	2
230 kV Overloads	0
138 kV Overloads	13
115 kV Overloads	3

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	49
500 kV Overloads	13
345 kV Overloads	0
230 kV Overloads	21
138 kV Overloads	3
115 kV Overloads	5

Scenario 0M

Scenario Components

1A-Alter_ALL (Full DOM proposals) _ 500 kV Stork-Flys UG Line

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23
- DOM: 2022-W3-711 (Regional Solution South)
- DOM/FE: 2022-W3-516/23 (DOM/FE Interregional Solution)
- TRANSRC: 2022-W3-858 (500 kV Stork-Flys UG Line)
- DOM: 2022-W3-923 (500 kV Dooms-Lexington)
- DOM: 2022-W3-671 (Front Royale-Morrisville)
- DOM: 2022-W3-731 (Locks TX Upgrade)
- DOM: 2022-W3-704/211 (Hollymeade-Gordonsville)
- DOM: 2022-W3-30/967 (Charlottesville-Hollymeade-Dooms)
- DOM: 2022-W3-74 (Ladysmith-Fredericksburg)

Note: Grab Aspen bus + 2nd 500 kV line from Aspen to Goose Creek from 2022-W3-692

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	20
500 kV Overloads	0
345 kV Overloads	1
230 kV Overloads	2
138 kV Overloads	13
115 kV Overloads	2

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	49
500 kV Overloads	14
345 kV Overloads	0
230 kV Overloads	18
138 kV Overloads	4
115 kV Overloads	5

Scenario 0N

Scenario Components

1A-Alter_ALL (Full DOM proposals)_500 kV Goose Creek-Beaumeade UG Line

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23
- DOM: 2022-W3-711 (Regional Solution South)
- DOM/FE: 2022-W3-516/23 (DOM/FE Interregional Solution)
- LSPower: 2022-W3-548 (500 kV Goose Creek-Beaumeade UG Line + Loop 230 kV Beaumeade - DTC through BECO)
- DOM: 2022-W3-923 (500 kV Dooms-Lexington)
- DOM: 2022-W3-671 (Front Royale-Morrisville)
- DOM: 2022-W3-731 (Locks TX Upgrade)
- DOM: 2022-W3-704/211 (Hollymeade-Gordonsville)
- DOM: 2022-W3-30/967 (Charlottesville-Hollymeade-Dooms)
- DOM: 2022-W3-74 (Ladysmith-Fredericksburg)

Note: Grab Aspen bus + 2nd 500 kV line from Aspen to Goose Creek from 2022-W3-692

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	25
500 kV Overloads	0
345 kV Overloads	1
230 kV Overloads	0
138 kV Overloads	18
115 kV Overloads	4

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	52
500 kV Overloads	13
345 kV Overloads	0
230 kV Overloads	24
138 kV Overloads	4
115 kV Overloads	5

Scenario 0O

Scenario Components

1A-Alter_OK+ Conastone-Doubs 500 kV line loop in T-Point + Otter Creek-T-Point 500 kV

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/23
- DOM: 2022-W3-692
- DOM: 2022-W3-923
- DOM: 2022-W3-671
- DOM: 2022-W3-731
- DOM: 2022-W3-704
- DOM: 2022-W3-211
- DOM: 2022-W3-30
- DOM: 2022-W3-967
- DOM: 2022-W3-74
- PSEG: Part of 2022-W3-637 (Conastone-Doubs 500 kV line) and loop in T-Point
- NEET: part of 175 (Otter Creek-T-Point)

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	19
500 kV Overloads	1
345 kV Overloads	2
230 kV Overloads	0
138 kV Overloads	13
115 kV Overloads	2

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	31
500 kV Overloads	8
345 kV Overloads	0
230 kV Overloads	15
138 kV Overloads	1
115 kV Overloads	2

Scenario 0O2

Scenario Components

1A-Alter_OK+ Otter Creek-T-Point 500 kV

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/23
- DOM: 2022-W3-692
- DOM: 2022-W3-923
- DOM: 2022-W3-671
- DOM: 2022-W3-731
- DOM: 2022-W3-704
- DOM: 2022-W3-211
- DOM: 2022-W3-30
- DOM: 2022-W3-967
- DOM: 2022-W3-74
- NEET: part of 175 (Otter Creek-T-Point)

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	18
500 kV Overloads	1
345 kV Overloads	2
230 kV Overloads	0
138 kV Overloads	11
115 kV Overloads	3

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	34
500 kV Overloads	7
345 kV Overloads	0
230 kV Overloads	17
138 kV Overloads	1
115 kV Overloads	4

Scenario 0O3

Scenario Components

0O2 (1A-Alter_OK+ Otter Creek-T-Point-Doubs 500 kV) + Remove Fort Martin-Doubs ckt 2 and Hunterstown-Carroll 230 kV line

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23 – Remove Fort Martin-Doubs ckt 2 and Hunterstown-Carroll 230 kV line
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/23
- DOM: 2022-W3-692
- DOM: 2022-W3-923
- DOM: 2022-W3-671
- DOM: 2022-W3-731
- DOM: 2022-W3-704
- DOM: 2022-W3-211
- DOM: 2022-W3-30
- DOM: 2022-W3-967
- DOM: 2022-W3-74
- NEET: part of 175 (Otter Creek - T-Point-Doubs)

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	34
500 kV Overloads	6
345 kV Overloads	0
230 kV Overloads	16
138 kV Overloads	3
115 kV Overloads	5

Scenario 0P

Scenario Components

(OG + updated 9A)

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/23
- DOM: 2022-W3-692
- DOM: 2022-W3-923
- DOM: 2022-W3-671
- DOM: 2022-W3-731
- DOM: 2022-W3-704
- DOM: 2022-W3-211
- DOM: 2022-W3-30
- DOM: 2022-W3-967
- DOM: 2022-W3-74
- Transource: part of 2022-W3-487 (IEC)

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	35
500 kV Overloads	4
345 kV Overloads	0
230 kV Overloads	24
138 kV Overloads	1
115 kV Overloads	3

Scenario 0P2

Scenario Components

(OG + updated 9A East)

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/23
- DOM: 2022-W3-692
- DOM: 2022-W3-923
- DOM: 2022-W3-671
- DOM: 2022-W3-731
- DOM: 2022-W3-704
- DOM: 2022-W3-211
- DOM: 2022-W3-30
- DOM: 2022-W3-967
- DOM: 2022-W3-74
- Transource: part of 2022-W3-487 (IEC East only)

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	44
500 kV Overloads	5
345 kV Overloads	0
230 kV Overloads	24
138 kV Overloads	4
115 kV Overloads	5

Scenario 0P NGME

Scenario Components

1A-Alter_ALL (Full DOM proposals) _ Remove Golden-2-Mars Extension

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23
- DOM: 2022-W3-711 (Regional Solution South)
- DOM/FE: 2022-W3-516/23 (DOM/FE Interregional Solution)
- DOM: 2022-W3-692 (DC Alley Solution) – Remove Golden-2-Mars Extension
- DOM: 2022-W3-923 (500 kV Dooms-Lexington)
- DOM: 2022-W3-671 (Front Royale-Morrisville)
- DOM: 2022-W3-731 (Locks TX Upgrade)
- DOM: 2022-W3-704/211 (Hollymeade-Gordonsville)
- DOM: 2022-W3-30/967 (Charlottesville-Hollymeade-Dooms)
- DOM: 2022-W3-74 (Ladysmith-Fredericksburg)

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	53
500 kV Overloads	13
345 kV Overloads	0
230 kV Overloads	23
138 kV Overloads	4
115 kV Overloads	5

Scenario 0Q

Scenario Components

0G remove Graceton-High Ridge 500 kV line + Peach Bottom -Brandon Shore 500 kV line (Part of 741)

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/23
- DOM: 2022-W3-692
- DOM: 2022-W3-923
- DOM: 2022-W3-671
- DOM: 2022-W3-731
- DOM: 2022-W3-704
- DOM: 2022-W3-211
- DOM: 2022-W3-30
- DOM: 2022-W3-967
- DOM: 2022-W3-74
- Remove Graceton-High Ridge 500 kV line
- Add Peach Bottom -Brandon Shore 500 kV line (Part of 741)

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	67
500 kV Overloads	15
345 kV Overloads	0
230 kV Overloads	29
138 kV Overloads	6
115 kV Overloads	8

Scenario 0Q2

Scenario Components

0G [1A-Alter_ALL (Full DOM proposals)] + Remove Pruntytown-Mt Storm, Fort Martin-Doubs ckt 2 and Hunterstown-Carroll 230 kV line

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23 – Remove Pruntytown-Mt Storm, Fort Martin-Doubs ckt 2 and Hunterstown-Carroll 230 kV line
- DOM: 2022-W3-711 (Regional Solution South)
- DOM/FE: 2022-W3-516/23 (DOM/FE Interregional Solution)
- DOM: 2022-W3-692 (DC Alley Solution) – Remove Golden-2-Mars Extension
- DOM: 2022-W3-923 (500 kV Dooms-Lexington)
- DOM: 2022-W3-671 (Front Royale-Morrisville)
- DOM: 2022-W3-731 (Locks TX Upgrade)
- DOM: 2022-W3-704/211 (Hollymeade-Gordonsville)
- DOM: 2022-W3-30/967 (Charlottesville-Hollymeade-Dooms)
- DOM: 2022-W3-74 (Ladysmith-Fredericksburg)

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	83
500 kV Overloads	15
345 kV Overloads	0
230 kV Overloads	26
138 kV Overloads	26
115 kV Overloads	10

Scenario 0Q3

Scenario Components

0G [1A-Alter_ALL (Full DOM proposals)] + Remove Fort Martin-Doubs ckt 2 and Hunterstown-Carroll 230 kV line

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23 – Remove Fort Martin-Doubs ckt 2 and Hunterstown-Carroll 230 kV line
- DOM: 2022-W3-711 (Regional Solution South)
- DOM/FE: 2022-W3-516/23 (DOM/FE Interregional Solution)
- DOM: 2022-W3-692 (DC Alley Solution) – Remove Golden-2-Mars Extension
- DOM: 2022-W3-923 (500 kV Dooms-Lexington)
- DOM: 2022-W3-671 (Front Royale-Morrisville)
- DOM: 2022-W3-731 (Locks TX Upgrade)
- DOM: 2022-W3-704/211 (Hollymeade-Gordonsville)
- DOM: 2022-W3-30/967 (Charlottesville-Hollymeade-Dooms)
- DOM: 2022-W3-74 (Ladysmith-Fredericksburg)

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	60
500 kV Overloads	14
345 kV Overloads	0
230 kV Overloads	25
138 kV Overloads	7
115 kV Overloads	9

Scenario 0Q4

Scenario Components

0G (1A-Alter_ALL (Full DOM proposals))_ Remove Fort Martin-Doubs ckt 1 and 2 and Hunterstown-Carroll 230 kV line

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23 – Remove Fort Martin-Doubs ckt 1 and 2 and Hunterstown-Carroll 230 kV line
- DOM: 2022-W3-711 (Regional Solution South)
- DOM/FE: 2022-W3-516/23 (DOM/FE Interregional Solution)
- DOM: 2022-W3-692 (DC Alley Solution) – Remove Golden-2-Mars Extension
- DOM: 2022-W3-923 (500 kV Dooms-Lexington)
- DOM: 2022-W3-671 (Front Royale-Morrisville)
- DOM: 2022-W3-731 (Locks TX Upgrade)
- DOM: 2022-W3-704/211 (Hollymeade-Gordonsville)
- DOM: 2022-W3-30/967 (Charlottesville-Hollymeade-Dooms)
- DOM: 2022-W3-74 (Ladysmith-Fredericksburg)

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	72
500 kV Overloads	14
345 kV Overloads	0
230 kV Overloads	27
138 kV Overloads	16
115 kV Overloads	10

Scenario 0R

Scenario Components

1A-Alter_OK+ Conastone-Doubs 500 kV line loop in T-Point + Otter Creek-T-Point 500 kV

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/23
- DOM: 2022-W3-692
- DOM: 2022-W3-923
- DOM: 2022-W3-671
- DOM: 2022-W3-731
- DOM: 2022-W3-704
- DOM: 2022-W3-211
- DOM: 2022-W3-30
- DOM: 2022-W3-967
- DOM: 2022-W3-74
- PSEG: Part of 2022-W3-637 (Conastone-Doubs 500 kV line) and loop in T-Point
- NEET: part of 175 (Otter Creek-T-Point)

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	30
500 kV Overloads	8
345 kV Overloads	0
230 kV Overloads	14
138 kV Overloads	1
115 kV Overloads	2

Scenario 0R2

Scenario Components

1A-Alter_OK+ Otter Creek-T-Point 500 kV

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/23
- DOM: 2022-W3-692
- DOM: 2022-W3-923
- DOM: 2022-W3-671
- DOM: 2022-W3-731
- DOM: 2022-W3-704
- DOM: 2022-W3-211
- DOM: 2022-W3-30
- DOM: 2022-W3-967
- DOM: 2022-W3-74
- NEET: part of 175 (Otter Creek-T-Point)

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	34
500 kV Overloads	7
345 kV Overloads	0
230 kV Overloads	17
138 kV Overloads	1
115 kV Overloads	4

Scenario 0S

Scenario Components

0G + remove Graceton-High Ridge 500 kV line + Remove High Ridge 500/230 station + Add Peach Bottom-New Raphael-Waugh Chapel 500 kV line and Raphael 500/230 station (Part of 808)

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/23
- DOM: 2022-W3-692
- DOM: 2022-W3-923
- DOM: 2022-W3-671
- DOM: 2022-W3-731
- DOM: 2022-W3-704
- DOM: 2022-W3-211
- DOM: 2022-W3-30
- DOM: 2022-W3-967
- DOM: 2022-W3-74
- Remove Graceton-High Ridge 500 kV line and Remove High Ridge 500/230 kV station
- PSEG: 2022-W3-808 Part (Add Peach Bottom-New Raphael-Waugh Chapel 500 kV line and Raphael 500/230 station)

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	55
500 kV Overloads	14
345 kV Overloads	0
230 kV Overloads	26
138 kV Overloads	4
115 kV Overloads	5

Document Revision History

10/17/2023 – R1: original version posted

11/30/2023 – R2:

- Update to cost estimates included in the "Final Reliability Analysis and Recommended Solution" section, reflecting latest estimates received.
- Correction to Map 5 - South Proposal Cluster Map.

12/8/2023 – R3:

- Update to cost estimates included in the "Final Reliability Analysis and Recommended Solution" section, reflecting latest estimates received consistent with Dec. 5, 2023 TEAC.
- Corrected footnote in Table 3.
- Clarification of sentences on pages 20, 22 and 23.