RELIABILITY FIRST

CORPORATION

Long Term Resource Assessment 2010-2019

October 2010

Table of Contents

Introduction

All Reliability*First* Corporation (RFC) members are affiliated with either the Midwest ISO (MISO) or the PJM Interconnection (PJM) regional transmission organization (RTO) for market operations and reliability coordination. Ohio Valley Electric Corporation (OVEC), a generation and transmission company located in Indiana, Kentucky and Ohio, is not a member of either RTO and is not affiliated with their markets; however, PJM performs OVEC's Reliability Coordinator services. Also, RFC does not have officially designated subregions. The Midwest ISO and PJM each operate as a single Balancing Authority area. Since all RFC demand is in either Midwest ISO or PJM, except for a small load (less than 100 MW) within the OVEC Balancing Authority area, the reliability of the PJM RTO and Midwest ISO are assessed, and the results used to indicate the reliability of the RFC region.

This assessment provides information on the projected resource adequacy for the 2010 through 2019 time period across the RFC region. The RFC Resource Adequacy Assessment Standard BAL-502-RFC-02, requires Planning Coordinators to identify the minimum planning reserves to maintain resource adequacy for their respective areas of RFC. PJM and Midwest ISO are the Planning Coordinators for their market areas. The reserve requirements in this assessment are based upon the explicit probability analyses conducted by these two Planning Coordinators in RFC.

In this report, Demand Response (DR) is defined as the demand that can be interrupted for system emergencies. The report for the RFC region includes the resources and demand only in the RFC area operated by PJM, Midwest ISO and OVEC. The remaining area of PJM operates within the SERC region, and the remaining area of Midwest ISO operates in the MRO or SERC regions. Demand, capacity and interchange values for RFC are rounded to the nearest 100 MW.

Both PJM and Midwest ISO have processes in place to review the reliability impacts of planned retirements prior to the scheduled retirement date. Any potential reliability issues must first be mitigated before the scheduled retirement can occur. However, there are currently a number of potential environmental regulations which may affect future unit retirement plans. Since current retirement schedules do not include the impact of these potential regulations, the potential impact on reliability has not been reviewed by PJM, Midwest ISO or Reliability*First*.

Executive Summary

Reserve Margins

The projected reserve margin for the PJM RTO is 26.1 percent in 2010 and 28.8 percent in 2019, based on net internal demand (NID) and existing, future and conceptual Net Capacity Resources. These reserve margins are adequate to satisfy the PJM reserve margin requirements throughout the assessment period. Comparable reserve margins in last year's long term assessment were 31.7 percent in 2009 and 18.9 percent in 2018.

The projected reserve margin for the Midwest ISO is 25.5 percent in 2010 and 16.5 percent in 2019, based on NID and existing, future and conceptual Net Capacity Resources. These reserve margins are adequate to satisfy the Midwest ISO reserve margin requirements throughout the assessment period. Comparable reserve margins in last year's long term assessment were 21.6 percent in 2009 and 15.5 percent in 2018.

The projected reserve margin for the Reliability*First* region is 28.0 percent (48,000 MW) in 2010 and 25.8 percent (49,400) in 2019, based on NID and existing, future and conceptual Net Capacity Resources. Both Midwest ISO and PJM have sufficient resources to satisfy their planning reserve requirements throughout the assessment period. Therefore, the resulting reserve margins for the Reliability*First* region are adequate throughout the assessment period. Comparable reserve margins in last year's long term assessment were 27.2 percent in 2009 and 18.2 percent in 2018.

Demand Growth Rates

The aggregate connected NID in the ReliabilityFirst region for the summer peak is projected to increase by about 20,500 MW from 171,500 MW in 2010, to 191,300 MW in 2019. The compound annualized growth rate (CAGR) in Net Internal Demand for the period 2010 to 2019 is 1.2 percent per year.

Net Capacity Resources

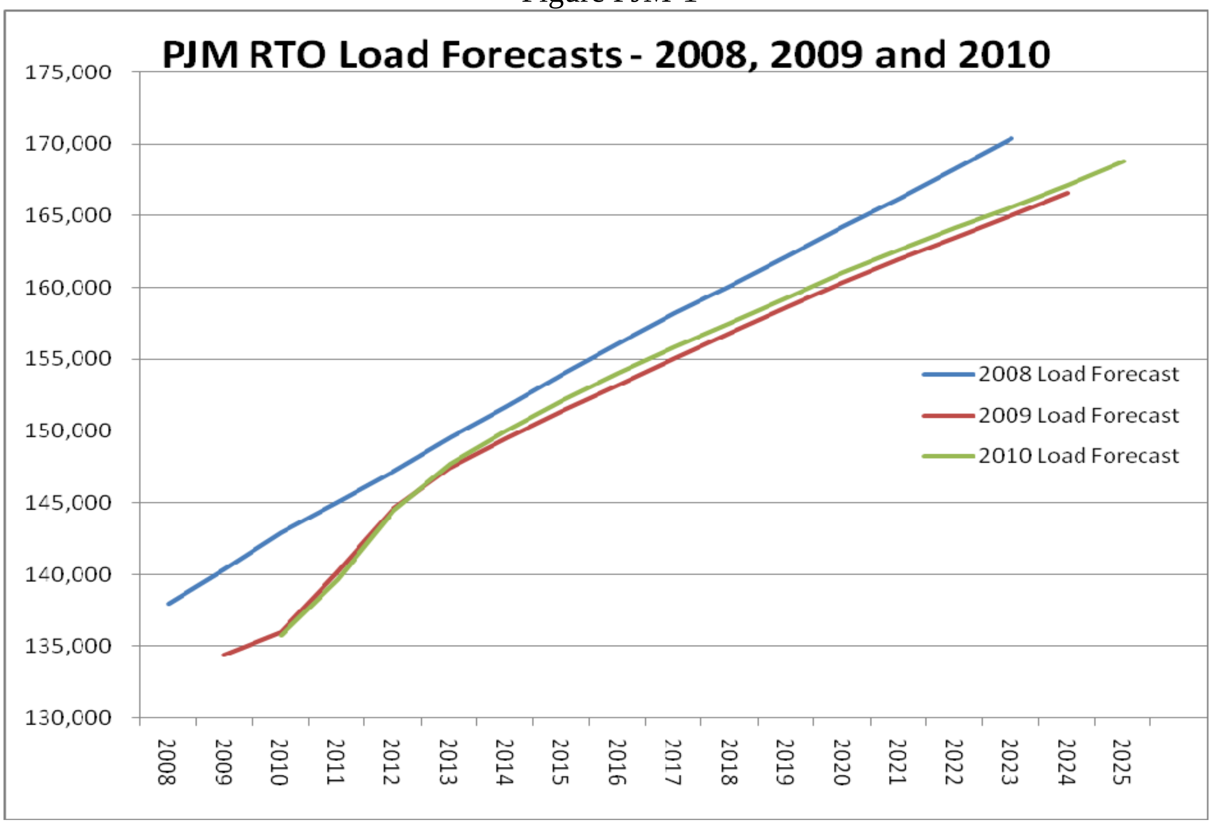
The reported generating unit capacity for the summer of 2010 is 217,700 MW. Future, Planned capacity changes project a net increase of 15,700 MW through 2019. Approximately 5,400 MW, 30 percent of the conceptual capacity resources (17,700 MW) are also expected through 2019. This is a total expected increase of 21,100 MW to 238,800 MW. A net power import of 1,900 MW is projected throughout the assessment period, resulting in Net Capacity Resources of 219,600 MW in 2010 and 240,700 MW in 2019.

PJM RTO

Demand

An anticipated economic rebound in 2010 will cause load growth to resume in 2010. Summer peak load growth for the PJM RTO is projected to average 1.7 percent per year over the next 10 years. The PJM RTO summer peak is forecasted to be 161,047 MW in 2020, a 10-year increase of 25,297 MW. Annualized 10-year growth rates for individual PJM transmission zones range from 1.0 percent to 2.5 percent. Compared to the 2009 long-term forecast of summer peak demand, the 2010 forecast of Total Internal Demand (TID) is very similar (Figure PJM-1). Significant differences in the forecast of Net Internal Demand from the 2009 PJM Load Report result from a large increase in expected Load Management and energy efficiency impacts.

Figure PJM-1



The economic variable used in the PJM load forecast is Real Gross Metropolitan Product (GMP) for major metropolitan areas within the PJM RTO. The current forecast uses the November 2009 economic forecast release from Moody's Economy.com. The 2010 forecast uses economic growth assumptions which closely parallel those from the 2009 forecast: an economic rebound will take hold and accelerate through 2012, then moderate through the remainder of the forecast horizon. For the PJM RTO, the

assumption for economic growth for the 10-year forecast is for GMP to grow at a compound average growth rate of 2.4 percent for 2010 to 2020.

PJM forecasts the load of the entire RTO and the individual transmission zones on a coincident basis. As PJM is summer-peaking, the coincident summer peaks are used in resource adequacy evaluations.

Energy efficiency programs included in the 2010 load forecast are impacts approved for use in the PJM Reliability Pricing Model. At time of the 2010 load forecast publication, nearly 550 MW of energy efficiency programs have been approved as Reliability Pricing Model resources. Measurement and verification of energy efficiency programs are governed by rules specified in PJM Manual 18B. To demonstrate the value of an energy efficiency resource, resource providers must comply with the measurement and verification standards defined in this manual, by establishing measurement and verification plans, providing post-installation measurement and verification reports, and undergoing a measurement and verification audit.

For the 2010/2011 delivery year PJM had contractually interruptible demand side management of 9,053 MW. Similar values are anticipated through the assessment period. No demand-side management resources or energy efficiency is specifically used for meeting renewable portfolio standards.

The PJM load forecast process produces a weather distribution of peak load forecasts by applying a Monte Carlo simulation using 35 years of historical weather from 1974 to 2008. The official peak load forecast is the median (50/50) value but extreme peak forecasts (90/10) are also published. PJM demand forecasting methods have not fundamentally changed in the last year.

Generation

PJM has 165,747 MW of existing certain capacity for the 2010 planning period (June 2010 through May 2011). Future planned resources increase the capacity by 29,550 MW by the end of the assessment period.

Variable resources are only counted partially for PJM resource adequacy studies. Initially, both wind and solar initially utilize class average capacity factors which are 13 percent for wind and 38 percent for solar. Performance over the peak period is tracked and the class average capacity factor is supplanted with historic information. After three years of operation only historic performance over the peak period is used to determine the individual unit's capacity factor.

Nameplate wind resources amount to 3,340 MW presently and are expected to increase by 17,400 MW to 20,740 MW over the assessment period. Expected on peak wind is presently 516 MW and is expected to increase by 1,746 MW to 2,262 MW over the assessment period. There is currently 26 MW of solar capacity expected to be added over the assessment period. Expected on peak solar capacity is expected to be 14.7 MW by the end of the assessment period. There are currently 927 MW of biomass in PJM and 44 MW is planned.

PJM has an on-peak total of 13,316 MW of conceptual capacity over the assessment period. Conceptual nameplate wind resources are expected to increase by 17,142 MW over the assessment period. Conceptual on peak wind is expected to increase 2,228 MW over the assessment period. Conceptual

solar nameplate of 596 MW is proposed. PJM has 254 MW of conceptual biomass for the assessment period.

Only existing certain capacity and future planned capacity are counted towards meeting the reserve requirement in PJM. No conceptual capacity is counted until an Interconnection Service Agreement is executed. All proposals for new generation come through the PJM Regional Transmission Expansion Process to determine required transmission expansion if necessary. The calculation of commercial probability uses historically gathered information to assign probabilities to each of four stages: feasibility study complete, impact study complete, facility study complete, and signed Interconnection Service Agreement. The probability percentages are applied to the amount of queued resources in each category to come up with a commercial probability for aggregate resources for each year out[1].

Capacity Transactions on Peak

Firm imports total 3,229 MW for the PJM RTO. Firm exports total 2,806 MW for the PJM RTO. All transactions are firm for both generation and transmission. There are no expected or provisional transactions counted towards meeting the reserve margin requirements. No imports or exports are based on partial path reservations.

Reliability Assessment Analysis

PJM is expected to meet its Reserve Margins requirements through the entire 10 year period and has over 40,000 MW of generation in its interconnection queues. The PJM Reserve Margin requirement covers the planning year which runs June 1 through May 31 of the following year. The Reserve Margin requirement for planning years 2010 and 2011 is 15.5 percent, for 2012 it is 15.4 percent and for 2013 through 2019, the requirement is 15.3 percent. PJM is expected to meet its Reserve Margin requirements through 2015 with only existing and planned resources. There are sufficient Conceptual resources from the interconnection queue to satisfy the reserve margin requirements through the remainder of the assessment period.

PJM has adopted a Loss of Load Expectation (LOLE) standard of one occurrence in ten years. PJM performs an annual LOLE study to determine the reserve margin required to satisfy this criterion. The study recognizes, among other factors, load forecast uncertainty due to economics and weather, generator unavailability, deliverability of resources to load, and the benefit of interconnection with neighboring systems. The methods and modeling assumptions used in this study are available in PJM Manual 20[2] .The latest resource adequacy study was completed in November, 2009[3]. This study examined the period 2009 - 2019.

PJM resources increase from 166,000 MW in 2010 to over 195,000 MW by the end of 2020. Only resources committed to the PJM Reliability Pricing Model market and planned capacity additions were counted towards meeting the PJM reserve margin requirement.

1 http://www.pjm.com/planning/resource-adequacy-planning/resource-reports-info.aspx

2 http://www.pjm.com/documents/~/media/documents/manuals/m20.ashx

3 http://www.pjm.com/planning/resource-adequacy-planning/~/media/documents/reports/2009-pjm-reserve-requirement-study.ashx

The PJM reserve requirement is calculated and required for up to three years into the future. PJM assumes the last calculated PJM Reserve Requirement to apply to all subsequent years. After the three-year planning window, a commercial probability [4] is applied to the generator interconnection queues to determine how much generation in aggregate should be applied to resource adequacy in longer-term years.

PJM has very little traditional hydro generation and expects no problems with warm cooling water. There are no anticipated fuel delivery problems during the summer when PJM experiences its peak. A significant percentage of PJM generation has duel fuel capability.

Transmission-limited and energy-only units are not considered in PJM reliability analysis. They are modeled when performing generator interconnection studies to check short-circuit and dynamics performance.

Variable resources are counted partially for PJM resource adequacy studies. Initially, both wind and solar, utilize class average capacity factors which are 13 percent for wind and 38 percent for solar. Performance over the peak period is tracked and the class average capacity factor is supplanted with historic information. After three years of operation only historic performance over the peak period is used to determine the individual plant's capacity factor. Variable resources are treated just like other resources but with the resource adequacy assumptions mentioned previously. The penetration of variable resources in the capacity mix is small at this time, however, if necessary, special approaches may be developed in the future.

PJM's resource adequacy studies model only those demand response programs that are programs committed to PJM and under the direction of PJM Operations. Compliance with a PJM call for interruption is mandatory for these demand response programs. At the conclusion of each summer, these demand response programs must submit data to PJM verifying their ability to interrupt load up to their full value. Failure to provide such data will result in a significant financial penalty to the demand response provider.

Generator retirements are evaluated for reliability impacts as each retirement is proposed. If it is determined that a reliability impacts exists, the unit will not be allowed to retire until the reliability impacts are addressed. Generator retirement information is available on the PJM website[5].

[4] http://www.pjm.com/planning/resource-adequacy-planning/resource-reports-info.aspx
[5] http://www.pjm.com/planning/generation-retirements.aspx

MIDWEST ISO

Demand

The 2009 demand forecast resulted in a compound annual growth rate of 1.0 percent from 2009-2018 and the 2010 projections resulted in a similar 1.1 percent compound annual growth rate from 2010–2019. The slight increase in this growth rate is due to the new member additions. The demands as reported by Network Customers are weather normalized, or 50/50, forecasts. Historically, reported load forecasts have been accurate as each member has expert knowledge of their individual loads with respect to weather and economic assumptions.

An unrestricted non-coincident peak demand is created on a regional basis by summing the non-coincident monthly forecasts for the individual Load Serving Entities (LSE) in the larger regional area of interest. Using historic market data, a load diversity factor was calculated by observing the individual peaks of each Local Balancing Authority and comparing them against the system peak. By taking the product of the diversity factor and the unrestricted non-coincident peak demand, Midwest ISO is able to estimate a total internal demand. The Midwest ISO does not currently track energy efficiency programs, however, they may be reflected in individual LSE load forecasts. Midwest ISO currently separates Demand Resources into two separate categories, Interruptible Load and Direct Controlled Load Management (DCLM). Interruptible load of 2,874 MW projected for this assessment is the magnitude of customer demand (usually industrial) that, in accordance with contractual arrangements, can be interrupted at the time of peak by direct control of the system operator (remote tripping) or by action of the customer at the direct request of the system operator. DCLM of 467 MW projected for this assessment is the magnitude of customer service (usually residential) that can be interrupted at the time of peak by direct control of the applicable system operator. DCLM is typically used for "peak shaving." Midwest ISO relies on Network Customers to provide weather normalized forecasts that account for the potential variability in projected demand due to weather, economic, or other key factors.

Generation

The average annual capacity over this assessment's ten-year timeframe is 122,525 MW for Existing Certain capacity, 18,769 MW for Existing Other capacity, and 1,518 MW for Future capacity resources (Planned and Other). The average annual capacity over this assessment's ten-year timeframe is 699 MW for Existing Inoperable capacity, there are no projected Future Planned capacity resources, and 1,518 MW for Future Other capacity resources. Due to the intermittent nature of wind, it is difficult to predict the wind capacity available on peak. However, the Midwest ISO determined maximum wind capacity credits using an Equivalent Load Carrying Capacity, a metric commonly utilized by the National Renewable Energy Laboratory. The Midwest ISO used the Equivalent Load Carrying Capacity for wind generation and Loss of Load Expectation analyses for the Summer seasonal assessment. Wind shows an annual Existing Certain capacity of 197 MW over this assessment's ten-year timeframe which utilizes an eight percent capacity credit. The annual Existing-Other capacity for wind is 7,447 MW over this assessment's ten-year timeframe. Biomass shows an annual Existing Certain capacity of 171 MW over this assessment's ten-year timeframe. The average annual Conceptual

capacity resources is 32,276 MW over this assessment's ten-year timeframe with an average annual variable Capacity for Wind of 28,229 MW and Biomass of 166 MW.

The Midwest ISO utilizes Existing Certain and Net Firm Transaction resources for reliability analyses and Reserve Margin calculations. A historical study establishing confidence factors based on fuel type was applied to the Midwest ISO Generation Interconnection Queue. Based on these analyses, the Midwest ISO utilized an overall confidence factor of 16 percent for Adjusted Conceptual Resources and 82 percent for Adjusted Future resources.

Capacity Transactions on Peak

The Midwest ISO only reports power imports (not exports) to the Midwest ISO market or reported interchange transactions into the Midwest ISO market. The forecast reflects 5,549 MW of power imports from year-to-year. All these imports are firm and fully backed by firm transmission and firm generation. No imports assumptions are based on partial path reservations.

Reliability Assessment Analysis

Midwest ISO's system Planning Reserve Margin is determined for a planning year which runs from June 1 through May 31 of the following year. The for the 2010 planning year the Reserve Margin is 15.4 percent, unchanged from the 2009 planning year. The average annual Reserve Margin based on Existing Certain and Net Firm Transactions is 20.2 percent over this assessment's ten-year timeframe which is greater than 15.4 percent and the 2010 NERC Reference Margin level of 15.0 percent. The overall system Planning Reserve Margin was unchanged from 2009/10 assuming that LSEs maintain capacity resources for the following: 1) Resource Adequacy Requirements, 2) LSE requirements to reliably serve load, and 3) to meet LOLE expectations. The Midwest ISO has published a separate report further explaining the Planning Reserve Margin Findings.[6] The Midwest ISO conducted the 2010-2011 Loss of Load Study and introduced an unforced capacity reserve margin of 4.50 percent through utilizing GE Multi-Area Reliability Simulation software for Loss of Load analysis. This study can be found on the Midwest ISO website.[7]

The Existing Certain and Net Firm Transactions, which reflects an average annual value of 132,165 MW over this assessment's ten-year timeframe, is relied on to calculate the average annual reserve margin of 20.2 percent mentioned above. The Midwest ISO only reports power imports to the Midwest ISO market or reported interchange transactions into the Midwest ISO. The forecast reflects 5,549 MW of typical power imports (reported by the Midwest ISO as externals) from year-to-year to meet the target reserve margin levels. All these imports are firm and fully backed by firm transmission and firm generation. The forecasts project load monthly from 2010 to 2012 and beyond 2012, the forecasts are reflected on a seasonal basis. Reserve Margins are calculated consistently and Reserve Margin requirements do not differ over the assessment period.

[6] http://www.midwestmarket.org/publish/Document/4dfde8_124a04ca493_-7f5f0a48324a

[7] http://www.midwestiso.org/publish/Document/13b9ea_1265d1d192a_-7b910a48324a/2010%20LOLE%20Study%20Report.pdf?action=download&_property=Attachment

For inclusion in seasonal assessments, the Midwest ISO utilizes Energy Information Administration fuel forecasts to identify any system wide fuel shortages and there were none projected for the 2010 summer period. In addition to the seasonal assessments, the Midwest ISO's Independent Market Monitor submits a monthly report to the Midwest ISO's Board of Directors which covers fuel availability and security issues. During the operating horizon, the Midwest ISO relies on market participants to anticipate reliability concerns related to the fuel supply or fuel delivery. Since there are no requirements to verify the operability of backup fuel systems or inventories, supply adequacy and potential problems must be communicated appropriately by the market participants to enable adequate response time. The Midwest ISO does not analyze energy-only resources in the resource adequacy assessment, however, transmission-limited resources are considered.

There are large amounts of wind generation that must be integrated while meeting state Renewable Portfolio Standards within the Midwest ISO footprint. The Midwest ISO initiated the Regional Generation Outlet Study to develop a set of regionally coordinated transmission projects that meet both individual state Renewable Portfolio Standards and LSE renewable goals with the minimum costs directed to the consumer. Due to the intermittent nature of wind, there is difficulty in predicting the wind capacity available on peak. However, the Midwest ISO determines a maximum wind capacity credit using an Equivalent Load Carrying Capacity, a metric commonly utilized by the National Renewable Energy Laboratory. The wind capacity credit is used for wind generation and Loss of Load Expectation analyses.

Demand Response reduces the total internal demand to arrive at the net internal demand. The Midwest ISO currently separates Demand Resources into two separate categories, Direct Controlled Load Management and Interruptible Load. If peak demands are higher than expected, the Midwest ISO can call the Local Balancing Authorities to deploy Demand Response, however, the Local Balancing Authorities also have the option to independently deploy Demand Response that they may have. There are no other expected changes to the planning approaches.

There are currently no foreseeable unit retirements which will have significant impact on reliability.

The Midwest ISO conducts an annual Long-Term Assessment to identify any reliability issues and addresses them. The Assessment includes an analysis over a ten year time frame evaluating demand, capacity, and reserve margins. In addition, the Assessment includes a risk assessment section which analyzes case studies while ensuring that LOLE requirements are met throughout the assessment timeframe.

Demand

The region is expected to be summer peaking throughout the study period, therefore this assessment will focus its analysis on the summer demand period. In this assessment, the data related to the Reliability*First* areas of PJM (RFC-PJM) and Midwest ISO (RFC-MISO) are combined with the data from OVEC to develop the Reliability*First* regional data. The demand forecasts used in this assessment are all based on the coincident peak demand of Midwest ISO's local balancing authorities and the coincident peak of PJM's load zones. Both PJM and Midwest ISO demand forecasts are based on an expected or 50/50 demand forecast. These forecasts reflect economic factors from late 2009 economic forecasts and median weather data. Actual demand data from the past three years indicates minimal diversity (less than 100 MW) between the RTO coincident peak demands and the Reliability*First* coincident peak demands. For this assessment, no additional diversity is included for the Reliability*First* region; therefore, the Reliability*First* coincident peak demand is simply the sum of the PJM, Midwest ISO and OVEC peak demands (rounded to nearest 100 MW). The composite Reliability*First* region forecast is considered a 50/50 demand forecast.

Midwest ISO has not specifically identified any reductions to their demand forecast explicitly due to energy efficiency programs, although the effects of these programs may be included in its members' forecast data. PJM has a forecast demand reduction of 550 MW due to energy efficiency programs which begins with the 2012 summer demand forecast. The categories of Direct Control Load Management and Interruptible are expected to provide a combined potential Demand Response reduction of 6,200 MW within the Reliability*First* region increasing to 9,300 MW through the assessment period. The Direct Control Load Management during the 2010 summer is projected to be 900 MW, and the Interruptible Demand is projected to be 5,300 MW. The total demand reduction is the maximum controlled demand mitigation that is expected to be available during peak demand conditions.

PJM has reported that an additional 5,100 MW of load was bid into PJM's 2010 market as a capacity resource. In this assessment, the additional demand response reduction is not included.

Since demand reduction programs are a contractual management of system demand, their implementation reduces the reserve margin requirement for the RTO. Net internal demand is TID less the demand reduction. Reserve margin requirements are based on net internal demand.

TABLE 1							
SUMMER PEAK FORECAST Demand, Demand Side Management, and Interruptible Loads 2010 - 2019							
Reliability*First* Regional Demand							
	PJM Coincident TID	**MISO Coincident TID**	**OVEC TID**	**RFC Coincident TID**	**PJM Demand Response**	**MISO Demand Response**	**RFC Net Internal Demand (NID)**
	MW	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**
2010	116,700	60,900	100	177,700	3,800	2,400	171,500
2011	120,000	61,800	100	181,900	4,100	2,400	175,400
2012	124,000	62,800	100	186,900	6,900	2,400	177,600
2013	126,700	63,100	100	189,900	6,900	2,400	180,600
2014	128,500	63,400	100	192,000	6,900	2,400	182,700
2015	130,200	63,400	100	193,700	6,900	2,400	184,400
2016	131,600	63,900	100	195,600	6,900	2,400	186,300
2017	133,000	64,200	100	197,300	6,900	2,400	188,000
2018	134,300	64,500	100	198,900	6,900	2,400	189,600
2019	135,600	64,900	100	200,600	6,900	2,400	191,300

The estimated coincident Net Internal Demand (NID) peak of the entire Reliability*First* region for the summer of 2010 is projected to be 171,500 MW. For the summer of 2019, NID is projected to be 191,300 MW. The compound annualized growth rate (CAGR) of the NID forecast is 1.2 from 2010 to 2019. This is lower than the 1.4 percent CAGR of last year's NID forecast due to the current forecast of expected economic conditions.

The TID for the summer of 2010 is projected to be 177,700 MW. For the summer of 2019, TID is projected to be 200,600 MW. The CAGR of the TID forecast is 1.4 percent from 2010 to 2019. This is the same as the 1.4 percent CAGR of last year's TID forecast.

The following figures show comparisons of actual demand data to ten year forecasts of demand.

Figure 1
Reliability*First*

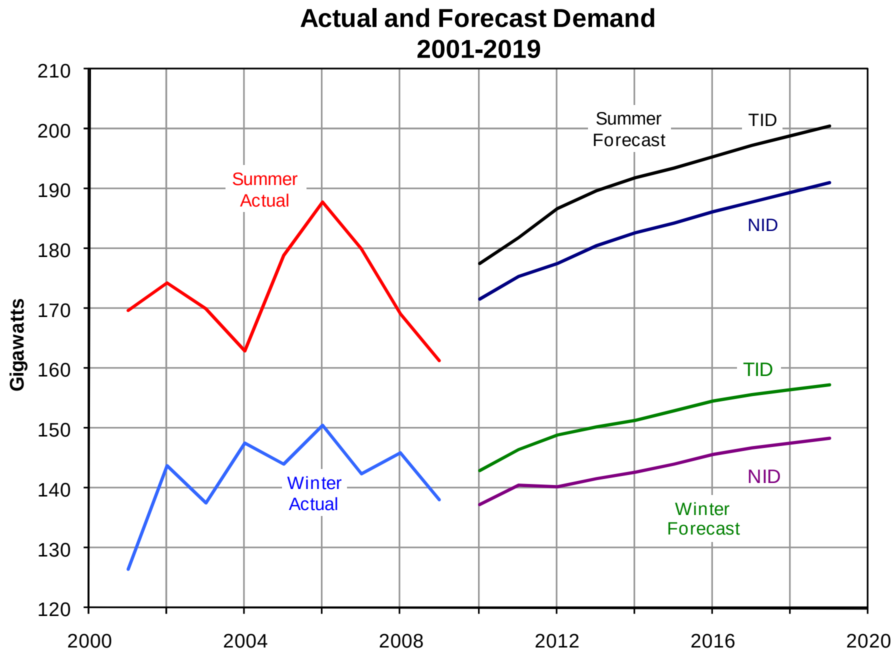
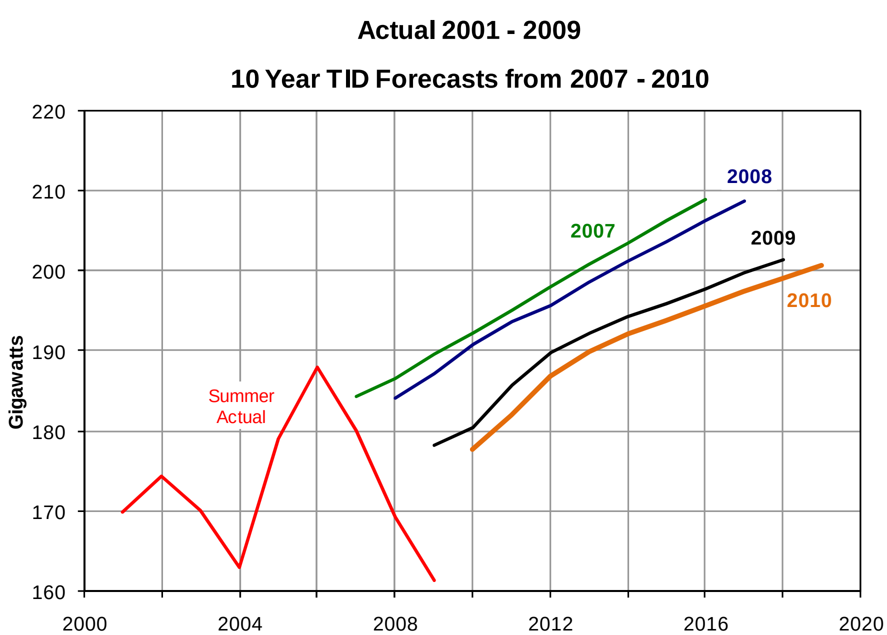


Figure 2
Reliability*First* Summer Peak Demand Data



Generation

The amount of Existing, Certain capacity in Reliability*First* is 217,700 MW. There is also 9,400 MW of Other Existing capacity in the ten year assessment period, which is not included in the reserve margins analysis.

PJM and Midwest ISO analyze historical data from their respective generator interconnection queues. This analysis and the status of each project's interconnection service agreement determines whether a project is categorized as Future, Planned or Conceptual, and the confidence factor to apply to Conceptual projects.

The nameplate rating increase in Future Capacity Additions through 2019 is 29,500 MW, with 15,700 MW being Future Planned Capacity that is included in the reserve margins.

The nameplate ratings of the Conceptual projects in the generator interconnection queues total 33,700 MW. The expected on-peak ratings of these projects total 17,700 MW. The amount of Conceptual capacity in the reserve calculation (5,400 MW) is the on-peak rating of the Conceptual capacity with an average 30 percent confidence factor.

This brings the expected capacity for demand and reserves to 238,800 MW in 2019. This is an expected 21,100 MW on-peak capacity increase from more than 63,000 MW of nameplate generator projects from the PJM and Midwest ISO generator interconnection queues.

The Other Existing Capacity resources are the existing generation resources within the RTOs or region that is not included in the reserve margin calculations. Included in this category would be the derated portion of wind/variable resources, generating capacity that has not been studied for delivery within the RTO, and capacity located within the RTO that is not part of PJM committed capacity or Midwest ISO Capacity Resources. Also, units scheduled for maintenance and any existing generators that are inoperable for this summer are excluded from the Existing, Certain Capacity category when determining reserve margins.

The capacity represented by the Existing Capacity less the Other Existing Capacity is the category of Existing, Certain Capacity, which is comprised of the existing resources in PJM's Reliability Pricing Model and the capacity resources in the Midwest ISO market.

The recent emphasis on renewable resources is increasing the amount of wind power capacity being added to systems in the Reliability*First* Region. In this assessment, the amount of available wind power capability included in the reserve calculations is less than the nameplate rating of the wind resources.

PJM uses a three year average of actual wind capability during the summer daily peak periods as the expected wind capability. Until three years of operating data is available for a specific wind project, a percentage of the capability is assigned for each missing year of data for that project. Some projects in the PJM generator interconnection queue use the formerly allowed 20 percent capability for wind, while newer projects use the current 13 percent capability factor.

In previous years, Midwest ISO allowed wind power providers to declare as a capacity resource, up to 20 percent of the nameplate capability. Beginning in 2010, the maximum wind capacity credit in the Midwest ISO is determined by using a technique that calculates the Equivalent Load Carrying Capacity for wind generation. The 2010 value is 8 percent of nameplate rating and is used in this assessment for each future wind project in the Midwest ISO.

Within Reliability*First* in 2010, there are 4,100 MW of existing nameplate wind turbine capacity with 500 MW being included as on-peak capacity for reserve requirements. Future Planned wind turbines are projected to add 16,700 MW of nameplate capacity and 2,900 MW of on-peak capacity. Another 700 MW of on-peak wind capacity is projected from the Conceptual resources.

The current 5,800 MW of additional existing renewable resources, including pumped hydro, is projected to increase to 6,300 MW within the region. The 700 MW of biomass (renewable) resources included in the Reliability*First* reserve margins in 2010 is projected to increase to 800 MW during the assessment period from the expected Future, Planned and Conceptual resources identified from the generator interconnection queues.

TABLE 2

Reliability*First*
SUMMER CAPABILITY
2010 - 2019

	Planned	w/ Planned [1]	Conceptual	Confidence factor [2]	w/ Planned & Conceptual	Uncertain	RFC Net Transactions
Existing Summer							
2010	0	217,684	-		217,684	9,400	1,900
2011	6,450	224,134	3,385	32.4%	225,231	9,400	1,900
2012	4,075	228,209	2,569	25.1%	229,950	9,400	1,900
2013	2,436	230,645	1,409	29.7%	232,805	9,400	1,900
2014	381	231,026	1,849	20.0%	233,556	9,400	1,900
2015	754	231,780	5,021	18.1%	235,221	9,400	1,900
2016	0	231,780	320	20.0%	235,285	9,400	1,900
2017	1,640	233,420	1,563	100.0%	238,488	9,400	1,900
2018	0	233,420	-		238,488	9,400	1,900
2019	0	233,420	1,600	20.0%	238,808	9,400	1,900
Net Change	15,736	15,736	17,716		21,124		

[1] - Existing capacity includes OVEC, and the Reliability*First* areas of PJM and MISO.
[2] - The confidence factor is a weighted average from the PJM and MISO factors.

Capacity Transactions on Peak

Firm power imports into the Reliability*First* regional area are forecast to be 2,500 MW in 2010, with firm power exports forecast to be 600 MW. These transactions all have firm transmission service and are assumed to remain at these levels through the 2011-2019 forecast period. Therefore, net interchange is forecast to be a 1,900 MW import each year into the Reliability*First* regional area, and it is included in the reserve margin calculations. There are no transactions using Liquidated Damage Contracts or make-whole contracts.

Reliability Assessment Analysis

Analyses were conducted by the Midwest ISO (LOLE Working Group) and PJM at the end of 2009 or early in 2010 to satisfy the Reliability*First* requirement for Planning Coordinators to determine the reserve margin at which the LOLE is one day in ten years (0.1 day/year) on an annual basis for their planning area. Both PJM and Midwest ISO conduct their analyses over a planning year that runs June 1 through May 31 of the following year. These analyses include demand forecast uncertainty, outage schedules, the determination of transmission transfer capability, internal deliverability, Capacity Benefit Margin and other external emergency sources, treatment of operating reserves and other relevant factors when determining the probability of firm demand exceeding the available generating capacity. The assessment of resource adequacy is based on reserve requirements determined from these analyses.

The PJM Reserve Margin requirement for the 2010 and 2011 planning years is 15.5 percent. The Reserve Margin requirement for the 2012 planning year is 15.4 percent and for the 2013through 2019 planning years the requirement is 15.3 percent. Similarly, the assessment of Midwest ISO resource adequacy is based on reserve requirements determined from its analysis. The Midwest ISO's reserve margin target for 2010 is 15.4 percent, and is used to assess each of the ten years in this analysis.

Reliability*First's* Resource Assessment Subcommittee believes that it is reasonable to assess the overall resource adequacy of the Reliability*First* regional area by assessing the resource adequacy of the RTOs that operate within the regional area. This is possible since the determination of each of the RTO reserve margin targets has been performed in a manner consistent with the requirements contained in regional reliability standard BAL-502-RFC-002. The Resource Assessment Subcommittee believes that when Reliability*First* has determined that each RTO is projected to have sufficient resources to satisfy their respective reserve margin requirement, therefore the Reliability*First* area is projected to have adequate resources.

Deliverability of capacity between the RTOs is not addressed in this report. However, each of the reserve requirement studies conducted has assumed limited or no transfer capability between these two RTOs. Studies by the Eastern Interconnection Reliability Assessment Group indicate there is more than 4,000 MW of transfer capability between the two RTOs.[8] The limited use of transfer capability in the reserve requirement studies provides a level of conservatism in this assessment.

[8] 2010 Summer SERC East-RFC Interregional Transmission System Reliability Assessment
2010 Summer RFC-NPCC Interregional Transmission System Reliability Assessment
2010 Summer MRO-RFC-SERC West-SPP Interregional Transmission System Reliability Assessment

It is important to note that the capacity resources identified as Existing, Certain in this assessment have been pre-certified by either PJM or Midwest ISO as able to be utilized within their RTO market area for the first year of the assessment period. This means that these resources are considered to be fully deliverable within and recallable by their respective markets. Both PJM and Midwest ISO include in the Existing, Certain category only those generator resources determined to satisfy their respective deliverability requirements. In both RTOs there are additional resources identified as Other Existing that may be available to serve load.

Reliability*First* has not performed any sensitivity analyses for high resource unavailability or high demand due to weather conditions. Any condition that increases regional demand or generation resource unavailability beyond the forecast conditions in the assessment analysis will decrease overall resource reliability. However, over the ten year assessment period, extreme weather, fuel interruptions, and droughts are considered to be short term conditions that are not included when determining long term reliability targets. Over time, any adverse trends in forced outage rates will be factored into the analyses required by the Reliability*First* Planned Resource Adequacy Standard, and the reserve margin targets will reflect the need for higher reserves.

The PJM projected reserve margin for summer 2010 is 26.1 percent which is in excess of the required reserve margin of 15.5 percent. The reserve margin reference for 2019 used in this assessment is 15.3 percent. The projected reserve margin for summer 2019 is 28.8 percent. The PJM RTO is projected to have adequate reserves through the assessment period.

The Midwest ISO projected reserve margin for summer 2010 is 25.5 percent which is in excess of the required reserve margin of 15.4 percent. The projected reserve margin in 2019 is 16.5 percent. Using the 15.4 percent reserve margin requirement for 2010 as the reference reserve margin through 2019, the Midwest ISO is projected to have adequate reserves through the assessment period.

Since PJM and Midwest ISO are projected to have sufficient resources to satisfy their respective reserve margin requirements, Reliability*First* expects the regional area to have adequate reserve margins throughout the entire assessment period.

FIGURE 3

Reliability*First*
Summer Reserve Margin Projections
2010 - 2019

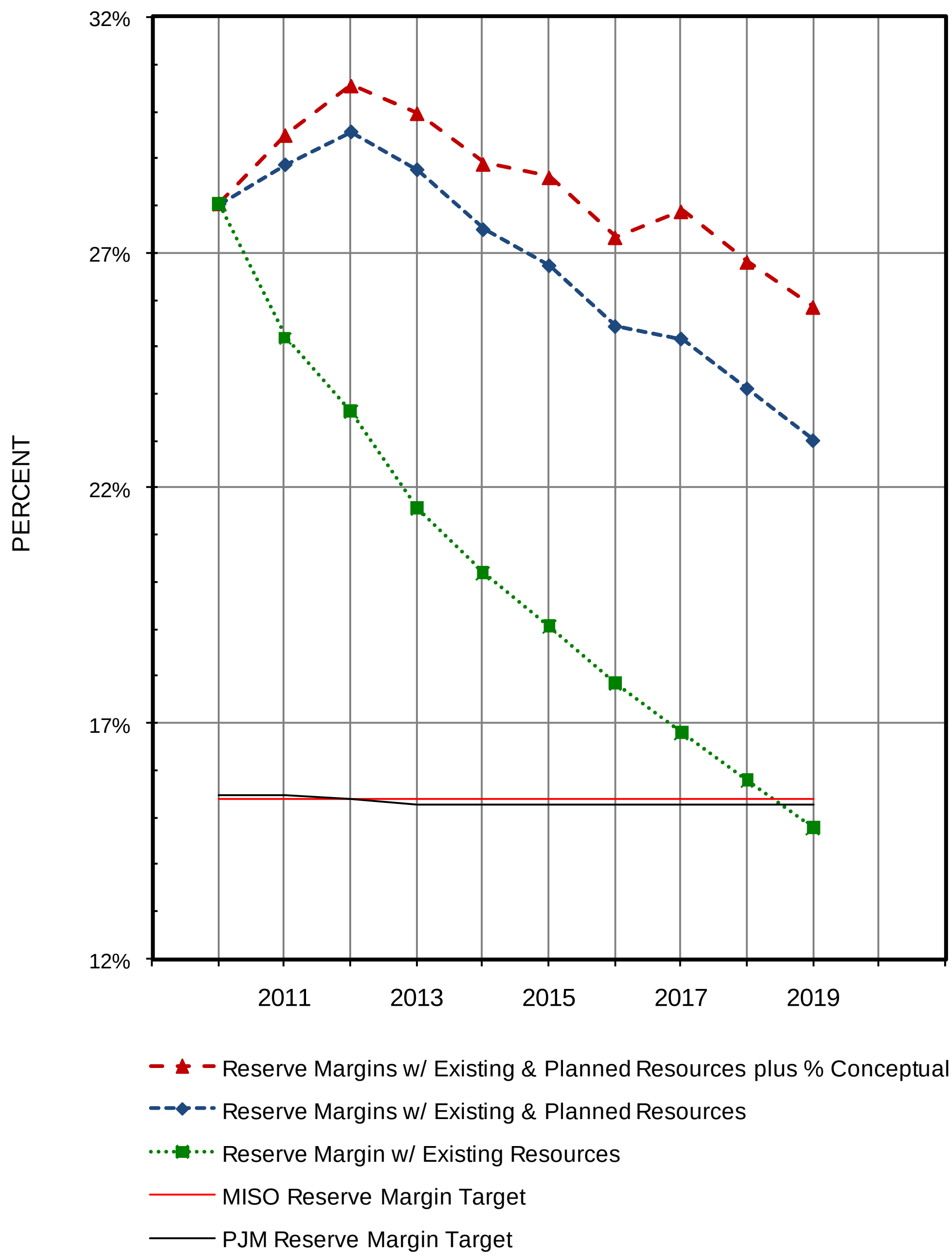


TABLE 3
DEMAND, CAPABILITY, AND MARGINS
Reliability*First*

2010 - 2014

	SUMMER SEASON				
	2010	2011	2012	2013	2014
DEMAND					
Reliability*First* Net Internal Demand, MW	171,500	175,400	177,600	180,600	182,700
CAPABILITY					
Existing Seasonal Capability (NSC), MW	217,684	217,684	217,684	217,684	217,684
Net transactions	1,900	1,900	1,900	1,900	1,900
Net Capacity Resources w/ Existing	219,584	219,584	219,584	219,584	219,584
Planned Additions (NSC), MW	-	6,450	10,525	12,961	13,342
	219,584	226,034	230,109	232,545	232,926
Conceptual Seasonal Capability (NSC), MW	-	3,385	5,954	7,363	9,212
Percentage of Conceptual (Cumulative Confidence Level) [1]	0.0%	32.4%	29.2%	29.3%	27.5%
Net Capacity Resources w/ Conceptual	219,584	227,131	231,850	234,705	235,456
RESERVE MARGINS (MW & % of NID)					
Reserve Margin w/ Existing Resources	48,084	44,184	41,984	38,984	36,884
	28.0%	25.2%	23.6%	21.6%	20.2%
Reserve Margin w/ Existing & Planned Resources	48,084	50,634	52,509	51,945	50,226
	28.0%	28.9%	29.6%	28.8%	27.5%
Reserve Margin w/ Existing, Planned & % of Potential Resources	48,084	51,731	54,250	54,105	52,756
	28.0%	29.5%	30.5%	30.0%	28.9%

2015 - 2019

	SUMMER SEASON				
	2015	2016	2017	2018	2019
DEMAND					
Reliability*First* Net Internal Demand, MW	184,400	186,300	188,000	189,600	191,300
CAPABILITY					
Existing Seasonal Capability (NSC), MW	217,684	217,684	217,684	217,684	217,684
Net transactions	1,900	1,900	1,900	1,900	1,900
Net Capacity Resources w/ Existing	219,584	219,584	219,584	219,584	219,584
Planned Additions (NSC), MW	14,096	14,096	15,736	15,736	15,736
	233,680	233,680	235,320	235,320	235,320
Conceptual Seasonal Capability (NSC), MW	14,233	14,553	16,116	16,116	17,716
Percentage of Conceptual (Cumulative Confidence Level) [1]	24.2%	24.1%	31.4%	31.4%	30.4%
Net Capacity Resources w/ Conceptual	237,121	237,185	240,388	240,388	240,708
RESERVE MARGINS (MW & % of NID)					
Reserve Margin w/ Existing Resources	35,184	33,284	31,584	29,984	28,284
	19.1%	17.9%	16.8%	15.8%	14.8%
Reserve Margin w/ Existing & Planned Resources	49,280	47,380	47,320	45,720	44,020
	26.7%	25.4%	25.2%	24.1%	23.0%
Reserve Margin w/ Existing, Planned & Conceptual Resources	52,721	50,885	52,388	50,788	49,408
	28.6%	27.3%	27.9%	26.8%	25.8%

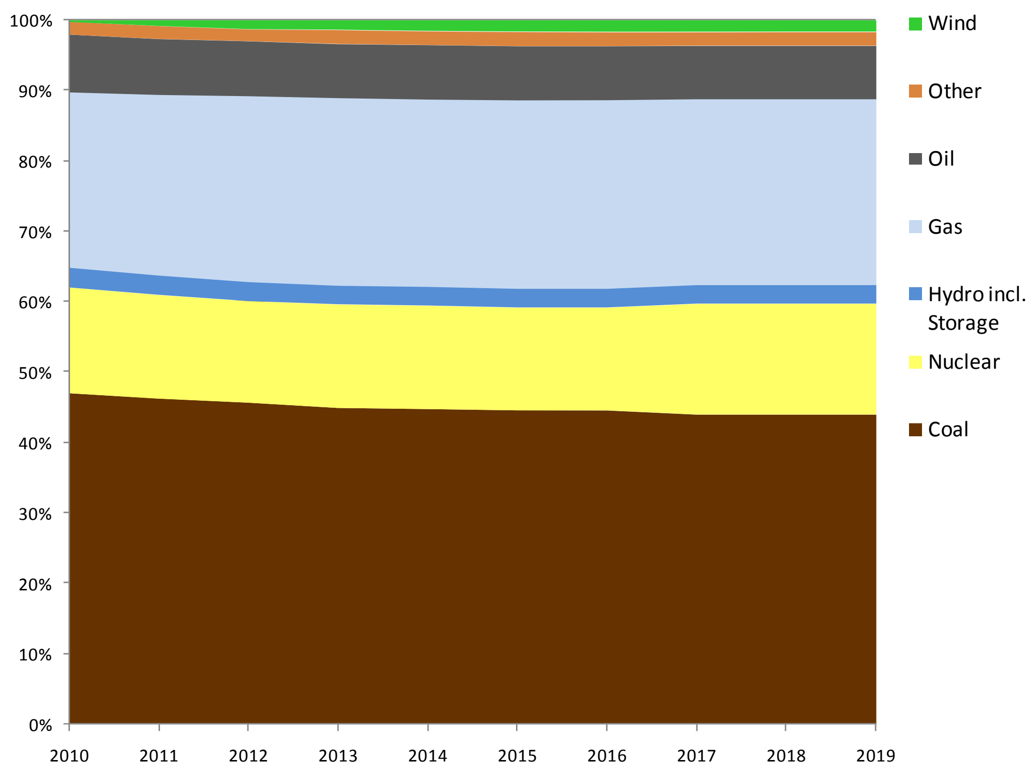
[1] - This is a cumulative confidence factor. Table 2 uses the annual confidence factor.

Both Midwest ISO and PJM conduct comprehensive detailed generator load deliverability studies[9]. For more information on PJM deliverability, see Appendix E of the PJM Manual 14b[10]. Results of the PJM analysis are evaluated continuously as part of the normal PJM planning process and presented as part of the Transmission Expansion Advisory Committee meetings[11]. Neither Midwest ISO nor PJM have any deliverability concerns for this assessment period.

Reliability*First* members are ready to mitigate any fuel supply disruption that may occur. Some members may resort to fuel switching for those units with dual-fuel capability, if it becomes necessary to maintain reliable fuel supplies. Data available to Reliability*First* indicates that at least 10 percent of the regional capacity has dual-fuel capability. Reliability*First* does not anticipate the need for any fuel switching in order to maintain reliable fuel supplies for the long term assessment. The following figure shows the expected on-peak fuel mix within the Reliability*First* region over the assessment period.

Figure 4
Reliability*First*
Fuel Mix
(Summer Peak Capability)

2010 - 2019



9 See: http://www.midwestmarket.org/page/Generator+Interconnection+Support+Documents
10 See: http://www.pjm.com/documents/~/media/documents/manuals/m14b.ashx
11 See: http://www.pjm.com/committees-and-groups/committees/teac.aspx

Since there currently are no adverse conditions affecting the resources within the Reliability*First* region, this assessment assumes that any future adverse weather or fuel supply issues would be temporary in duration and limited in impact on resource availability, and will not affect the results of the reserve margin analysis. No other unusual operating conditions that could impact reliability are foreseen for this assessment period.

Transmission-limited and energy-only units are not considered in reliability analysis. They are modeled when performing generator interconnection studies to check short-circuit and dynamics performance.

Variable resources are only counted partially for PJM resource adequacy studies. Both wind and solar initially use class average capacity factors, which are 13 percent for wind and 38 percent for solar. Performance over the peak period is tracked and the class average capacity factor is supplanted with historic information. After three years of operation, only historic performance over the peak period is used to determine the individual unit's capacity factor.

There are large amounts of wind generation that must be integrated while meeting state Renewable Portfolio Standards within the Midwest ISO footprint. Due to the intermittent nature of wind, there is difficulty in predicting the wind capacity available on peak. Beginning in 2010, the maximum wind capacity credit in the Midwest ISO is determined by using a technique that calculates the Equivalent Load Carrying Capacity for wind generation. This method is linked to a Loss of Load Expectation. In this assessment the maximum on-peak capacity for future wind generation is 8 percent of nameplate rating.

Both PJM and Midwest ISO have processes in place to review the reliability impacts of planned retirements prior to the scheduled retirement date. Any potential reliability issues must first be mitigated before the scheduled retirement can occur. However, there are currently a number of potential environmental regulations which may affect future unit retirement plans. Since current retirement schedules do not include the impact of these potential regulations, the potential impact on reliability has not been reviewed by PJM, Midwest ISO or Reliability*First*.

APPENDIX A

Acronyms

CAGR – Compound Annual Growth Rate

DCLM – Direct Control Load Management

DR – Demand Response

GMP – Gross Metropolitan Product

ISO – Independent (transmission) System Operator

LOLE – Loss Of Load Expectation

LSE – Load Serving Entity

MISO – Midwest Independent Transmission System Operator

MRO – Midwest Reliability Organization

NID – Net Internal Demand

OVEC – Ohio Valley Electric Corporation

PJM – PJM RTO

RFC – Reliability*First* Corporation

RTO – Regional Transmission Organization

SERC – SERC Reliability Corporation

TID – Total Internal Demand

APPENDIX B

Generator Queue Data

RTO	Queue ID	Project Name or Interconnection point	Maximum or Nameplate	MW Planned	MW Conceptual	Conceptual Reserves	Confidence Factor	In-Service Year	In-Service Month	Type	Fuel	State
MISO	J043	Carbon Tap 120 kV - Connecting to ITC at Jewel, St. Clair & Spokane substations	3.2		3.2	0.6	19.0%	2010	6	Biomass	Landfill Gas	MI
MISO	G774	Pere Marquette-Stronach 138 kV line	70.0		5.6	0.4	6.9%	2010	6	WT	Wind	MI
MISO	G905	Tap Begole-Tittabawassee 138kV line	200.0		16.0	1.1	6.9%	2010	6	WT	Wind	MI
MISO	G431	Edwardsport Gen Station	420.0		420.0	230.8	55.0%	2010	6	CC	coal	IN
MISO	G967	Thayer to Schahfer 138 kV line	101.0		8.1	0.6	6.9%	2010	7	WT	Wind	IN
MISO	G949	3 miles East of Linden, Indiana on Duke 138 kV line	200.0		16.0	1.1	6.9%	2010	10	WT	Wind	IN
MISO	G743	WPSC Cadillac-Leroy 69kV line	45.0		3.6	2.7	74.7%	2010	12	WT	Wind	MI
MISO	H075	At or near the Redwood Substation either on 69 kV (Wolverine) or 138 kV (ITC) lines	60.0		4.8	0.3	6.9%	2010	12	WT	Wind	MI
MISO	G833	Point Beach Unit 2	53.0		53.0	2.5	4.6%	2011	5	ST	Nuclear	WI
PJM	V2-028	Vienna	6.0	2.3		0.0		2011	6	PV	Solar	MD
PJM	U2-045	Huron 69kV	20.0	2.6		0.0		2011	6	WT	Wind	NJ
PJM	T39	Coudersport 46kV	18.0	3.6		0.0		2011	6	WT	Wind	PA
PJM	P40	Providence Heights WF	20.0	4.0		0.0		2011	6	WT	Wind	IL
PJM	T155	Belknap 25kV	6.0	6.0		0.0		2011	6	Hydro	Hydro	PA
PJM	U2-061	Roth Rock WF	50.0	6.5		0.0		2011	6	WT	Wind	MD
PJM	U1-059	Dunkirk 69kV	49.9	6.5		0.0		2011	6	WT	Wind	OH
PJM	U2-030	Four Mile Ridge WF - 24 WT	60.0	7.8		0.0		2011	6	WT	Wind	MD
PJM	R48	Paulding	48.3	9.7		0.0		2011	6	WT	Wind	OH
PJM	N36	Gold Sabinsville	50.0	10.0		0.0		2011	6	WT	Wind	PA
PJM	N32	South Chestnut WF	50.4	10.1		0.0		2011	6	WT	Wind	PA
PJM	U2-051	Glen Lyn-Wythe 138kV	60.0	10.4		0.0		2011	6	WT	Wind	VA
PJM	P60	Stony Creek WF	52.5	10.5		0.0		2011	6	WT	Wind	PA
PJM	U1-088	Dequine 345kV	100.0	13.0		0.0		2011	6	WT	Wind	IN
PJM	U4-028	Melmore Tap 138kV	100.0	13.0		0.0		2011	6	WT	Wind	OH
PJM	U2-015	Harwood-E. Palmerton 230kV	100.0	13.0		0.0		2011	6	WT	Wind	PA
PJM	U2-050	Lonesome Pine 138kV	100.0	13.0		0.0		2011	6	WT	Wind	VA
PJM	U1-066	Carlls Corner 69kV	91.0	18.0		0.0		2011	6	CT	Oil	NJ
PJM	S64	York Inc. 115kV	18.0	18.0		0.0		2011	6	ST	Biomass	PA
PJM	U1-087	Dequine 345kV	150.0	19.5		0.0		2011	6	WT	Wind	IN
PJM	U4-006	Mendota 138kV	20.0	20.0		0.0		2011	6	ST	Biomass	IL
PJM	O73	Benson 345kV	100.0	20.0		0.0		2011	6	WT	Wind	IL
PJM	K28	Kelso Gap WF	100.0	20.0		0.0		2011	6	WT	Wind	MD
PJM	T156	Champion	292.0	20.0		0.0		2011	6	ST	Coal	PA
PJM	T129	Liberty	541.0	20.0		0.0		2011	6		Natural Gas	PA
PJM	V1-026	Limerick	1,213.0	20.0		0.0		2011	6	ST	Nuclear	PA
PJM	V1-027	Limerick	1,213.0	20.0		0.0		2011	6	ST	Nuclear	PA
PJM	R89	Conowingo Hydro Station	572.0	24.0		0.0		2011	6	Hydro	Hydro	MD
PJM	U2-062	Randolph 138kV	187.5	24.4		0.0		2011	6	WT	Wind	OH
PJM	U4-001	Howard 138kV	200.0	26.0		0.0		2011	6	WT	Wind	OH
PJM	U2-073	Frostburg 138kV II	200.0	26.0		0.0		2011	6	WT	Wind	PA
PJM	U1-060	East Lima-South Kenton 138kV	201.0	26.1		0.0		2011	6	WT	Wind	OH
PJM	T131	Lincoln-Sterling 138kV	150.0	30.0		0.0		2011	6	WT	Wind	OH
PJM	S36	Kankakee 138kV	175.0	35.0		0.0		2011	6	WT	Wind	IL
PJM	S37	Kankakee 138kV	175.0	35.0		0.0		2011	6	WT	Wind	IL
PJM	M24	Beech Ridge WF	186.0	37.2		0.0		2011	6	WT	Wind	WV
PJM	U2-072	East Lima-Marysville 345kV	300.0	39.0		0.0		2011	6	WT	Wind	OH
PJM	U3-031	Lincoln Generating Facility	616.0	40.0		0.0		2011	6		Natural Gas	IL
PJM	R96	Lancaster-Maryland 138kV	200.0	40.0		0.0		2011	6	WT	Wind	IL

RTO	Queue ID	Project Name or Interconnection point	Maximum or Nameplate	MW Planned	MW Conceptual	Conceptual Reserves	Confidence Factor	In-Service Year	Month	Type	Fuel	State
PJM	T124	Latham-Pontiac I 345kV	200.0	40.0		0.0		2011	6	WT	Wind	IL
PJM	T125	Latham-Pontiac II 345kV	200.0	40.0		0.0		2011	6	WT	Wind	IL
PJM	T126	Olive-Dequine 345kV	200.0	40.0		0.0		2011	6	WT	Wind	IN
PJM	T127	Olive-Dequine 345kV	200.0	40.0		0.0		2011	6	WT	Wind	IN
PJM	T183	Olive-Dequine 345kV	200.0	40.0		0.0		2011	6	WT	Wind	IN
PJM	T184	Olive-Dequine 345kV	200.0	40.0		0.0		2011	6	WT	Wind	IN
PJM	S73	Lincoln-North Delphos	200.0	40.0		0.0		2011	6	WT	Wind	IN
PJM	Q57	Lee - DeKalb Wind Energy Center	240.0	48.0		0.0		2011	6	WT	Wind	IL
PJM	P36	Big Sky	240.0	48.0		0.0		2011	6	WT	Wind	IL
PJM	V1-035	ST	53.0	53.0		0.0		2011	6	WT	Other	WV
PJM	S72	Heartland?	300.0	60.0		0.0		2011	6	WT	Wind	IN
PJM	T130	Convoy-East Lima 345kV	300.0	60.0		0.0		2011	6	WT	Wind	OH
PJM	T142	Southwest Lima-Marysville 345kV	300.0	60.0		0.0		2011	6	WT	Wind	OH
PJM	R78	Heartland?	300.3	60.1		0.0		2011	6	WT	Wind	IL
PJM	R79	Heartland?	300.3	60.1		0.0		2011	6	WT	Wind	IL
PJM	Q50	Dresden Nuclear Station Unit 3	957.0	70.0		0.0		2011	6	ST	Nuclear	IL
PJM	T105	Loretto?	350.0	70.0		0.0		2011	6	WT	Wind	IL
PJM	R60	Convoy-East Lima 345kV	350.0	70.0		0.0		2011	6	WT	Wind	IN
PJM	Q79	Longview ST1	700.0	100.0		0.0		2011	6	ST	Coal	WV
PJM	R76	Hawks Nest Hydro	100.0	100.0		0.0		2011	6	Hydro	Hydro	WV
PJM	M12	Susquehanna #2	2,520.0	107.0		0.0		2011	6	ST	Nuclear	PA
PJM	Q51	Quad Cities - Units 1 & 2	2,018.0	194.0		0.0		2011	6	ST	Nuclear	IL
PJM	T45	Hudson 230kV	205.0	205.0		0.0		2011	6		Natural Gas	NJ
PJM	S17	Talbert 230kV	225.0	225.0		0.0		2011	6		Natural Gas	MD
PJM	Q11	Red Oak 230kV	300.0	300.0		0.0		2011	6		Natural Gas	NJ
PJM	R44	Cash Creek	485.0	485.0		0.0		2011	6	ST	Coal	KY
PJM	S107	Mickleton 230kV	580.0	580.0		0.0		2011	6		Natural Gas	NJ
PJM	N42	Great Bend	1,200.0	600.0		0.0		2011	6	ST	Coal	OH
PJM	T174	Yukon-Browns Run 500kV	930.0	900.0		0.0		2011	6		Natural Gas	PA
PJM	T94	Covert	1,035.0	1,035.0		0.0		2011	6	CC	Natural Gas	MI
PJM	V2-013	Kidd SP	0.5		0.2	0.1	30.0%	2011	6	PV	Solar	NJ
PJM	V3-051	Turkey Hill Dairy WF	3.2		0.4	0.1	30.0%	2011	6	WT	Wind	PA
PJM	V3-002	Ellicott City	1.2		0.5	0.1	30.0%	2011	6	PV	Solar	MD
PJM	V3-039	Harrison SP	2.0		0.8	0.2	30.0%	2011	6	PV	Solar	NJ
PJM	U2-059	Belvidere SP	2.0		0.8	0.2	30.0%	2011	6	PV	Solar	NJ
PJM	V4-038	Friendship Manor 34.5kV	1.0		1.0	0.3	30.0%	2011	6	IC	Methane	MD
PJM	V4-005	Pemberton 13.8kV	2.9		1.1	0.3	30.0%	2011	6	PV	Solar	NJ
PJM	V4-062	Upper Pittsgrove 6	3.0		1.1	0.3	30.0%	2011	6	PV	Solar	NJ
PJM	V4-017	Woodruffs Gap 345kV	3.5		1.3	0.4	30.0%	2011	6	PV	Solar	NJ
PJM	V4-028	Koller Road 13kV	4.0		1.5	0.5	30.0%	2011	6	PV	Solar	NJ
PJM	V2-027	South Milton	1.6		1.6	0.5	30.0%	2011	6	IC	Methane	PA
PJM	V1-021	Cape May County 12kV	1.9		1.7	0.5	30.0%	2011	6	IC	Methane	NJ
PJM	V1-032	Highland 69kV	5.0		1.9	0.6	30.0%	2011	6	PV	Solar	OH
PJM	V4-027	Quarryville	5.0		1.9	0.6	30.0%	2011	6	PV	Solar	PA
PJM	V2-005	Pleasantville 12kV	7.3		1.9	0.6	30.0%	2011	6	IC	Methane	NJ
PJM	V4-013	Gloucester 26kV	5.2		2.0	0.6	30.0%	2011	6	PV	Solar	NJ
PJM	U1-048	Reichs LF	2.0		2.0	0.6	30.0%	2011	6	IC	Methane	MD
PJM	U4-041	Valley 13.2kV	2.0		2.0	0.6	30.0%	2011	6	IC	Diesel	PA
PJM	U4-042	Hanover 13.2kV	2.0		2.0	0.6	30.0%	2011	6	IC	Diesel	PA
PJM	U4-043	Tolna 13.2kV	2.0		2.0	0.6	30.0%	2011	6	IC	Diesel	PA
PJM	U4-044	Stoverstown 13.2kV	2.0		2.0	0.6	30.0%	2011	6	IC	Diesel	PA
PJM	U4-045	Oil Creek 34.kV	2.0		2.0	0.6	30.0%	2011	6	IC	Diesel	PA
PJM	U4-046	Teepleville 34.5kV	2.0		2.0	0.6	30.0%	2011	6	IC	Diesel	PA
PJM	U4-047	Mill Village 34.5kV	2.0		2.0	0.6	30.0%	2011	6	IC	Diesel	PA
PJM	U4-048	Saegertown 34.5kV	2.0		2.0	0.6	30.0%	2011	6	IC	Diesel	PA
PJM	V3-019	Edinboro 13.8kV	2.0		2.0	0.6	30.0%	2011	6	IC	Natural Gas	PA
PJM	U4-040	Lincoln 13.2kV	2.0		2.0	0.6	30.0%	2011	6	IC	Natural Gas	PA
PJM	V2-002	Martinsburg	2.7		2.7	0.8	30.0%	2011	6	IC	Methane	PA

RTO	Queue ID	Project Name or Interconnection point	Maximum or Nameplate	MW Planned	MW Conceptual	Conceptual Reserves	Confidence Factor	In-Service Year	In-Service Month	Type	Fuel	State
PJM	V4-044	Mannington Township 2	7.0		2.7	0.8	30.0%	2011	6	PV	Solar	NJ
PJM	V4-043	Shirley 12kV	8.0		3.0	0.9	30.0%	2011	6	PV	Solar	NJ
PJM	V3-070	J. Rinco 34.5kV	8.0		3.0	0.9	30.0%	2011	6	PV	Solar	NJ
PJM	V4-011	North Findlay 34.5kV	3.2		3.2	1.0	30.0%	2011	6	IC	Methane	OH
PJM	V4-039	Church	9.0		3.4	1.0	30.0%	2011	6	PV	Solar	MD
PJM	V3-011	Sussex 12.47kV	3.4		3.4	1.0	30.0%	2011	6	IC	Methane	NJ
PJM	V3-025	English SP	10.0		3.8	1.1	30.0%	2011	6	PV	Solar	NJ
PJM	V3-024	Cranbury II SP	10.0		3.8	1.1	30.0%	2011	6	PV	Solar	NJ
PJM	V4-004	Roxbury 12.5kV	10.0		3.8	1.1	30.0%	2011	6	PV	Solar	NJ
PJM	V3-005	Morris 34.5kV	10.0		3.8	1.1	30.0%	2011	6	PV	Solar	NJ
PJM	V3-040	Siegfried-Hauto 69kV	10.0		3.8	1.1	30.0%	2011	6	PV	Solar	PA
PJM	V2-043	Upper Deerfield Township I	12.0		4.6	1.4	30.0%	2011	6	PV	Solar	NJ
PJM	V2-044	Upper Deerfield Township II	12.0		4.6	1.4	30.0%	2011	6	PV	Solar	NJ
PJM	V3-050	Penns Neck 13kV	4.6		4.6	1.4	30.0%	2011	6	IC	Natural Gas	NJ
PJM	V3-044	Glendon 34.5kV	4.8		4.8	1.4	30.0%	2011	6	IC	Methane	PA
PJM	V4-012	Morgantown	4.8		4.8	1.4	30.0%	2011	6	IC	Methane	PA
PJM	V3-037	Naval Academy Junction 34.5kV	5.0		5.0	1.5	30.0%	2011	6	IC	Natural Gas	MD
PJM	V4-052	West Reading	6.0		6.0	1.8	30.0%	2011	6	IC	Natural Gas	PA
PJM	V2-009	Cranbury SP	16.1		6.1	1.8	30.0%	2011	6	PV	Solar	NJ
PJM	U3-032	Traynor 34.5kV	20.0		6.5	2.0	30.0%	2011	6	PV	Solar	NJ
PJM	V2-046	Pilesgrove Township 12kV	19.9		7.0	2.1	30.0%	2011	6	PV	Solar	NJ
PJM	V4-009	Upper Deerfield	20.0		7.6	2.3	30.0%	2011	6	PV	Solar	NJ
PJM	V4-036	Newport-South Millville 69kV	20.0		7.6	2.3	30.0%	2011	6	PV	Solar	NJ
PJM	V2-010	Stewartsville 34.5kV	20.0		7.6	2.3	30.0%	2011	6	PV	Solar	NJ
PJM	V4-023	Upper Pittsgrove 1	20.0		7.6	2.3	30.0%	2011	6	PV	Solar	NJ
PJM	V4-024	Upper Pittsgrove 2	20.0		7.6	2.3	30.0%	2011	6	PV	Solar	NJ
PJM	V4-025	Upper Pittsgrove 3	20.0		7.6	2.3	30.0%	2011	6	PV	Solar	NJ
PJM	V4-041	Upper Pittsgrove 4	20.0		7.6	2.3	30.0%	2011	6	PV	Solar	NJ
PJM	V4-042	Upper Pittsgrove 5	20.0		7.6	2.3	30.0%	2011	6	PV	Solar	NJ
PJM	V4-029	Mannington Township	20.0		7.6	2.3	30.0%	2011	6	PV	Solar	NJ
PJM	V4-037	Pilesgrove 12kV	20.0		7.6	2.3	30.0%	2011	6	PV	Solar	NJ
PJM	V4-054	Fairfield Township 12kV	20.0		7.6	2.3	30.0%	2011	6	PV	Solar	NJ
PJM	V4-040	Orchard 230kV	20.0		7.6	2.3	30.0%	2011	6	PV	Solar	NJ
PJM	V3-013	Wilmington 69kV	20.0		7.6	2.3	30.0%	2011	6	PV	Solar	OH
PJM	V3-028	East Lima-Marysville 345kV	20.0		7.6	2.3	30.0%	2011	6	PV	Solar	OH
PJM	V3-031	Germantown	20.0		7.6	2.3	30.0%	2011	6	PV	Solar	PA
PJM	Q53	Chestnut Flats WF	38.0		7.6	2.3	30.0%	2011	6	WT	Wind	PA
PJM	T108	Archbald Generating Station	9.2		9.2	2.8	30.0%	2011	6	IC	Methane	PA
PJM	V3-047	Sutton Dam 69kV	9.9		9.9	3.0	30.0%	2011	6	Hydro	Hydro	WV
PJM	T118	Phillips Island CT1, CT2, CT3, CT4	840.0		10.0	3.0	30.0%	2011	6	CT	Natural Gas	PA
PJM	O52	Potter WF	50.0		10.0	3.0	30.0%	2011	6	WT	Wind	PA
PJM	Q36	Philipsburg - Tyrone North 115kV	50.0		10.0	3.0	30.0%	2011	6	WT	Wind	PA
PJM	V2-018	Tuckahoe	20.0		12.4	3.7	30.0%	2011	6	PV	Solar	NJ
PJM	U1-049	Kankakee #4 138kV	100.0		13.0	3.9	30.0%	2011	6	WT	Wind	IL
PJM	V1-011	Haviland 138kV	150.0		19.5	5.9	30.0%	2011	6	WT	Wind	OH
PJM	V1-024	LaSalle 1	1,188.0		20.0	6.0	30.0%	2011	6	ST	Nuclear	IL
PJM	V1-025	LaSalle 2	1,191.0		20.0	6.0	30.0%	2011	6	ST	Nuclear	IL
PJM	R20	Rock Springs Units 3 & 4	330.0		20.0	6.0	30.0%	2011	6	CT	Natural Gas	MD
PJM	Q34	Garrett 115kV	100.0		20.0	6.0	30.0%	2011	6	WT	Wind	PA
PJM	P59	Laurel Mountain Project	125.0		25.0	7.5	30.0%	2011	6	WT	Wind	WV
PJM	U1-037	LaSalle-Plano 345kV	250.0		32.5	9.8	30.0%	2011	6	WT	Wind	IL
PJM	R35	Robbins Community Power	50.0		50.0	15.0	30.0%	2011	6	ST	Biomass	IL
PJM	T120	Kankakee #3 138kV	250.0		50.0	15.0	30.0%	2011	6	WT	Wind	IL
PJM	V3-003	Greentown-Jefferson 765kV	500.0		65.0	19.5	30.0%	2011	6	WT	Wind	IN

RTO	Queue ID	Project Name or Interconnection point	Maximum or Nameplate	MW Planned	MW Conceptual	Conceptual Reserves	Confidence Factor	In-Service Year	Month	Type	Fuel	State
PJM	T133	Chalk Point-Bowie 230kV	225.0		225.0	67.5	30.0%	2011	6	CT	Natural Gas	MD
PJM	U2-095	Nelson 345kV	600.0		600.0	180.0	30.0%	2011	6	CC	Natural Gas	IL
PJM	G30_W51	Longview ST1	600.0		600.0	180.0	30.0%	2011	6	ST	Coal	WV
PJM	Q68	Kincaid 345kV	726.0		726.0	217.8	30.0%	2011	6	ST	Coal	IL
PJM	T157	New Creek Mountain 500kV	160.0	32.0		0.0		2011	6	WT	Wind	WV
PJM	V3-034	Red Oak 230kV	921.5		50.0	15.0	30.0%	2011	6		Natural Gas	NJ
		Market changes		-73.0								
		2011	33,383.8	6,449.4	3,385.4	1,096.5						
MISO	J089	Vectren Culley 138 kV substation	447.0		447.0	61.1	13.7%	2011	7	ST	Coal	IN
PJM	U1-010	Delta	575.0	18.0		0.0		2011	7		Natural Gas	PA
PJM	U2-080	South Portsmouth 138kV	134.0	134.0		0.0		2011	7	ST	Coal	KY
PJM	P04	Delta	557.0	550.0		0.0		2011	7		Natural Gas	PA
PJM	U2-054	Weissport	2.6		2.6	0.8	30.0%	2011	8	Hydro	Hydro	PA
MISO	J052	Manning substation 138kV	100.0		8.0	0.6	6.9%	2011	9	WT	Wind	MI
MISO	J065	Duke Indiana's 69 kV between Scottsburg & Speed	28.0		28.0	5.3	19.0%	2011	9	Biomass	Wood	IN
PJM	U4-007	Jennings Randolph Dam	14.0	13.4		0.0		2011	9	Hydro	Hydro	MD
PJM	V3-032	Breed-Dequine 345kV	200.0		26.0	7.8	30.0%	2011	9	WT	Wind	IL
PJM	O49	Wempletown-Byron 345kV	200.0	40.0		0.0		2011	9	WT	Wind	IL
PJM	O50	Powerton-Dresden 345kV	200.0	40.0		0.0		2011	9	WT	Wind	IL
PJM	V3-060	Antioch	20.0		2.6	0.8	30.0%	2011	9	WT	Wind	IL
MISO	J028	Attica - Lafayette 230 kV Line	200.0		16.0	1.1	6.9%	2011	10	WT	Wind	IN
PJM	U2-016	Grover 230kV	85.0	11.1		0.0		2011	10	WT	Wind	PA
PJM	U4-029	Melmore Tap 138kV	100.0	13.0		0.0		2011	10	WT	Wind	OH
PJM	S57	Collins	1,500.0	300.0		0.0		2011	10	WT	Wind	SD
PJM	S58	Collins	2,000.0	400.0		0.0		2011	10	WT	Wind	SD
PJM	V3-062	McConnellsburg-Guilford 138kV	20.0		7.6	2.3	30.0%	2011	10	PV	Solar	PA
PJM	K04_CE19	Freeport Wind Farm	80.0		16.0	4.8	30.0%	2011	10	WT	Wind	IL
PJM	R55	Dixon - Maryland 138kV	100.0	20.0		0.0		2011	11	WT	Wind	IL
PJM	R54	Dixon - Cherry Valley 138kV	100.0	20.0		0.0		2011	11	WT	Wind	IL
PJM	V3-014	Lee County	160.2		20.8	6.2	30.0%	2011	11	WT	Wind	IL
PJM	U1-051	Clearfield	130.0	16.9		0.0		2011	12	WT	Wind	PA
PJM	U2-042	East Lima-South Kenton 138kV	201.0	26.1		0.0		2011	12	WT	Wind	OH
PJM	U2-041	Hardin WF	300.0	39.0		0.0		2011	12	WT	Wind	OH
PJM	U2-058	Kincaid Wind	500.0		65.0	19.5	30.0%	2011	12	WT	Wind	IL
PJM	P28	Mehoopany 115kV	150.0		30.0	9.0	30.0%	2011	12	WT	Wind	PA
PJM	T16	Gorman-Snowy Creek 69kV	30.0	6.0		0.0		2011	12	WT	Wind	MD
PJM	U3-025	Elk Garden-Parr Run 138kV	80.0	10.4		0.0		2011	12	WT	Wind	WV
PJM	U2-091	Delaware-Richmond 138kV	100.0	13.0		0.0		2011	12	WT	Wind	IN
PJM	U2-092	Delaware-Centerville 138kV	100.0	13.0		0.0		2011	12	WT	Wind	IN
PJM	O68	Dixon-Cherry Valley 138kV	100.0	20.0		0.0		2011	12	WT	Wind	IL
PJM	U2-090	Desoto-Tanners Creek 345kV	200.0	26.0		0.0		2011	12	WT	Wind	IN
PJM	V4-055	Ravenswood 138kV	11.0		4.2	1.3	30.0%	2011	12	PV	Solar	OH
PJM	V4-053	Double Toll Gate 138kV	20.0		7.6	2.3	30.0%	2011	12	PV	Solar	VA
PJM	V4-059	Pine Creek 46kV	20.0		20.0	6.0	30.0%	2011	12	ST	Biomass	WV

RTO	Queue ID	Project Name or Interconnection point	Maximum or Nameplate	MW Planned	MW Conceptual	Conceptual Reserves	Confidence Factor	In-Service Year	In-Service Month	Type	Fuel	State
PJM	U4-011	Pontiac-Brokaw #1 345kV	200.0		26.0	7.8	30.0%	2011	12	WT	Wind	IL
PJM	U4-012	Pontiac-Brokaw #2 345kV	200.0		26.0	7.8	30.0%	2011	12	WT	Wind	IL
PJM	U4-037	Kincaid-Brokaw 345kV	201.0		26.1	7.8	30.0%	2011	12	WT	Wind	IL
PJM	V4-046	Byron 1	1,249.0		20.0	6.0	30.0%	2012	1	ST	Nuclear	IL
PJM	V4-047	Byron 2	1,223.0		20.0	6.0	30.0%	2012	1	ST	Nuclear	IL
PJM	V4-048	Braidwood 1	1,247.0		20.0	6.0	30.0%	2012	1	ST	Nuclear	IL
PJM	V4-049	Braidwood 2	1,219.0		20.0	6.0	30.0%	2012	1	ST	Nuclear	IL
PJM	U4-010	Pontiac-Latham 345kV	200.0		26.0	7.8	30.0%	2012	1	WT	Wind	IL
PJM	U3-008	Mt. Bethel 230kV	200.0		200.0	60.0	30.0%	2012	1		Oil	PA
PJM	O60	AMP Berlin WF	5.4	1.1		0.0		2012	1	WT	Wind	PA
PJM	T107	Essex 230kV	625.0	625.0		0.0		2012	1		Natural Gas	NJ
PJM	V1-012	Haviland 138kV	150.0		19.5	5.9	30.0%	2012	2	WT	Wind	OH
PJM	G06	Martins Creek #4	850.0	30.0		0.0		2012	3	ST	Coal	PA
PJM	S100	Clinch River 138kV	80.0	80.0		0.0		2012	3	ST	Coal	VA
PJM	Q43	Virginia City Hybrid Energy Center - 1 Unit	614.0	534.0		0.0		2012	3	ST	Coal	VA
PJM	O56	Dunning Mountain WF	76.0		15.2	4.6	30.0%	2012	3	WT	Wind	PA
PJM	V3-063	Dupont 69kV	20.0		20.0	6.0	30.0%	2012	3	ST	Biomass	VA
MISO	J071	Zimmer-Silver Grove-Red Bank 345 kV	112.0		112.0	1.9	1.7%	2012	4	Hydro	Water	OH
PJM	U3-021	Silver Lake-Cherry Valley	100.0		100.0	30.0	30.0%	2012	5		Natural Gas	IL
PJM	U4-027	Normandy-Kewanee 138kV	100.0		100.0	30.0	30.0%	2012	5		Natural Gas	IL
PJM	T134	Chalk Point-Bowie 230kV	325.0		325.0	97.5	30.0%	2012	5		Natural Gas	MD
PJM	U2-049	Monmouth	640.0	640.0		0.0		2012	5		Natural Gas	NJ
PJM	O19	Somerset (Kimberly Run) WF	33.0		6.6	2.0	30.0%	2012	5	WT	Wind	PA
MISO	J074	Harbor Beach to Wyat kV line	350.0		28.0	1.9	6.9%	2012	5	WT	Wind	MI
MISO	J075	Arrowhead to Cosmo Tap kV line	350.0		28.0	1.9	6.9%	2012	5	WT	Wind	MI
PJM	U4-003	Olive-Dequine 345kV	200.0	26.0		0.0		2012	6	WT	Wind	IN
PJM	T42	Kearny 138kV	89.0	79.0		0.0		2012	6		Natural Gas	NJ
PJM	Q90	Mickleton 230kV	650.0	650.0		0.0		2012	6		Natural Gas	NJ
PJM	R43	GCC Realty	20.0		4.0	1.2	30.0%	2012	6	WT	Wind	PA
PJM	V3-017	Morgantown-Oak Grove	725.0		725.0	217.5	30.0%	2012	6		Natural Gas	MD
		Market Changes		-321.0								
		2012	20,818.2	4,073.9	2,568.8	644.4						
MISO	J054	Kokomo to Noblesville 230kV / -86.168936, 40.364978	197.8		15.8	1.1	6.9%	2012	7	WT	Wind	IN
PJM	U2-055	Karthaus-Milesburg 230kV	89.1	11.5		0.0		2012	7	WT	Wind	PA
PJM	S70	Eureka 138kV	36.4	36.4		0.0		2012	7	Hydro	Hydro	WV
PJM	V1-033	Pumphrey 115kV	132.0	132.0		0.0		2012	7	ST	Other	MD
PJM	V2-020	Howard-West End Fostoria 138kV	150.0		19.5	5.9	30.0%	2012	7	WT	Wind	OH
PJM	V3-015	Keystone 345kV	300.0		39.0	11.7	30.0%	2012	8	WT	Wind	IN
PJM	V3-016	Greenville-West Milton 138kV	300.0		39.0	11.7	30.0%	2012	8	WT	Wind	OH
PJM	U2-066	Marysville-SW Lima 345kV	200.0	26.0		0.0		2012	9	WT	Wind	OH
PJM	U2-065	Kankakee 138kV	250.0		32.5	9.8	30.0%	2012	9	WT	Wind	IL
PJM	V3-053	Desoto 138kV	150.0		19.5	5.9	30.0%	2012	9	WT	Wind	IN
PJM	S71	Bluff Point 138kV	120.0	24.0		0.0		2012	10	WT	Wind	IN
PJM	U2-074	Peach Bottom-Rock Springs 500kV	650.0	650.0		0.0		2012	10	CC	Natural Gas	PA
PJM	V3-004	Siegfried	83.0		83.0	24.9	30.0%	2012	10	ST	Coal	PA
PJM	U3-030	Beaver Valley #2	951.0	38.0		0.0		2012	11	ST	Nuclear	PA
PJM	V3-064	Rivesville-Pruntytown 138kV	28.0		28.0	8.4	30.0%	2012	12	ST	Biomass	WV
PJM	V4-021	Keystone 345kV	300.0		39.0	11.7	30.0%	2012	12	WT	Wind	IN
PJM	V2-001	54 1.8 WT	97.2		11.3	3.4	30.0%	2012	12	WT	Wind	OH

RTO	Queue ID	Project Name or Interconnection point	Maximum or Nameplate	MW Planned	MW Conceptual	Conceptual Reserves	Confidence Factor	In-Service Year	Month	Type	Fuel	State
PJM	U4-002	Pickens-Monterville 138kV	100.0	13.0		0.0		2012	12	WT	Wind	WV
PJM	T84	Corson 138kV	350.0	70.0		0.0		2012	12	WT	Wind	NJ
PJM	V3-030	St. Benedict-Patton 46kV	32.2		4.0	1.2	30.0%	2012	12	WT	Wind	PA
PJM	V4-015	Fostoria Central 138kV	66.6		8.6	2.6	30.0%	2012	12	WT	Wind	OH
PJM	V3-018	Towanda 115kV	75.0		9.8	2.9	30.0%	2012	12	WT	Wind	PA
PJM	V3-042	Thompson 115kV	84.0		10.9	3.3	30.0%	2012	12	WT	Wind	PA
PJM	P52	Albright 138kV	80.0		16.0	4.8	30.0%	2012	12	WT	Wind	WV
PJM	V4-016	Valley 138kV	200.0		26.0	7.8	30.0%	2012	12	WT	Wind	MI
PJM	V2-023	Galion-Muskingham River 345kV	250.5		37.5	11.3	30.0%	2012	12	WT	Wind	OH
PJM	V4-033	Desoto 345kV	300.0		39.0	11.7	30.0%	2012	12	WT	Wind	IN
PJM	V3-055	Engle 69kV	50.0		50.0	15.0	30.0%	2013	1	ST	Biomass	KY
PJM	Q47	Peach Bottom - Units 2 & 3	2,532.0	140.0		0.0		2013	4	ST	Nuclear	PA
PJM	R17	CPV St. Charles	645.0	645.0		0.0		2013	6	CC	Natural Gas	MD
PJM	V4-019	Bergen 230kV	610.0		60.0	18.0	30.0%	2013	6		Natural Gas	NJ
PJM	V1-022	Plano 345kV	380.0		380.0	114.0	30.0%	2013	6		Natural Gas	IL
PJM	R11	South River	440.0		440.0	132.0	30.0%	2013	6		Natural Gas	NJ
		Market Changes		650.0								
		2013	10,229.8	2,435.9	1,408.4	418.9						
PJM	U3-002	Mullin-Greentown Tap 138kV	200.0	26.0		0.0		2013	7	WT	Wind	IN
PJM	Q20	Holtwood	249.0		140.0	28.0	20.0%	2013	7	Hydro	Hydro	PA
PJM	U4-038	Mullin-Greentown Tap 138kV	100.0	13.0		0.0		2013	9	WT	Wind	IN
PJM	U4-039	Greentown 138kV	800.0	104.0		0.0		2013	9	WT	Wind	IN
PJM	T143	Hennepin 600 MW	600.0		120.0	24.0	20.0%	2013	10	WT	Wind	IL
PJM	U3-029	Beaver Valley #1	950.0	37.0		0.0		2013	10	ST	Nuclear	PA
PJM	V3-056	Metropolitan Court 34.5kV	50.0		50.0	10.0	20.0%	2013	10	ST	Biomass	MD
PJM	T48	Coldwater-Rossburg 69kV	50.0	10.0		0.0		2013	11	WT	Wind	OH
PJM	V3-029	Chatfield 138kV	150.0		19.5	3.9	20.0%	2013	12	WT	Wind	OH
PJM	V3-027	Pickens 138kV	200.0		26.0	5.2	20.0%	2013	12	WT	Wind	WV
PJM	V1-010	Howard-Fostoria Central 138kV	300.0		39.0	7.8	20.0%	2013	12	WT	Wind	OH
PJM	V2-006	75 WT	150.0	19.5		0.0		2013	12	WT	Wind	OH
PJM	V3-010	Delaware-Modoc 138kV	100.0		13.0	2.6	20.0%	2013	12	WT	Wind	IN
PJM	V3-007	Desoto-Tanners Creek #1 345kV	200.0		26.0	5.2	20.0%	2013	12	WT	Wind	IN
PJM	V3-009	Desoto-Tanners Creek #2 345kV	200.0		26.0	5.2	20.0%	2013	12	WT	Wind	IN
PJM	V4-010	Fremont Center-Tiffin Center 138kV	250.0		32.5	6.5	20.0%	2013	12	WT	Wind	OH
PJM	V3-045	Zimmer-Spurlock 345kV	112.0		112.0	22.4	20.0%	2013	12	Hydro	Hydro	OH
PJM	V2-021	Clayville	64.0	64.0		0.0		2014	1	CT	Oil	NJ
PJM	T146	England	346.0	69.2		0.0		2014	1	WT	Wind	NJ
PJM	U3-009	Mt. Bethel 230kV	595.0		595.0	119.0	20.0%	2014	1		Oil	PA
PJM	U1-056	Lewis 138kV	350.0	45.5		0.0		2014	4	WT	Wind	NJ
PJM	U2-069	Frackville	56.0	7.3		0.0		2014	6	WT	Wind	PA
PJM	V4-020	North Temple 230kV	650.0		650.0	130.0	20.0%	2014	6		Natural Gas	PA
		Capacity Changes		-15.0								
		2014	6,722.0	380.5	1,849.0	369.8						
PJM	S101	Dresden	580.0	580.0		0.0		2014	7	CC	Natural Gas	OH
PJM	V4-002	Graceton 230kV	575.0		575.0	115.0	20.0%	2014	9		Natural Gas	PA
PJM	T35	Byron Wind IV	1,500.0		300.0	60.0	20.0%	2014	9	WT	Wind	ND
PJM	T33	Byron Wind II	1,500.0		300.0	60.0	20.0%	2014	9	WT	Wind	SD
PJM	T34	Byron Wind III	1,500.0		300.0	60.0	20.0%	2014	9	WT	Wind	SD
PJM	T32	Byron Wind I	2,500.0		500.0	100.0	20.0%	2014	9	WT	Wind	SD
PJM	V2-008	Kincaid 138kV	600.0		600.0	120.0	20.0%	2014	10	ST	Coal	IL

RTO	Queue ID	Project Name or Interconnection point	Maximum or Nameplate	MW Planned	MW Conceptual	Conceptual Reserves	Confidence Factor	In-Service Year	Month	Type	Fuel	State
MISO	G820	Port Calcite-Rockport 138kV line	600.0		600.0	82.0	13.7%	2014	10	ST	Coal	MI
PJM	P58	Canaan - Seneca 138kV	150.0	16.0		0.0		2014	12	WT	Wind	WV
PJM	V3-008	Desoto-Tanners Creek #1 345kV	200.0		26.0	5.2	20.0%	2014	12	WT	Wind	IN
PJM	U3-026	Collins	1,500.0		195.0	39.0	20.0%	2014	12	WT	Wind	SD
PJM	U1-074	Point Marion Lock & Dam	10.0	10.0		0.0		2015	1	Hydro	Hydro	PA
PJM	U1-081	Monongahela Lock & Dam #4	10.0	10.0		0.0		2015	1	Hydro	Hydro	PA
PJM	U1-082	Maxwell Lock & Dam	10.0	10.0		0.0		2015	1	Hydro	Hydro	PA
PJM	U1-079	Opekiska Lock & Dam	10.0	10.0		0.0		2015	1	Hydro	Hydro	WV
PJM	U1-075	Sutton Dam	12.0	12.0		0.0		2015	1	Hydro	Hydro	WV
PJM	U1-073	Allegheny Lock & Dam #7	16.0	16.0		0.0		2015	1	Hydro	Hydro	PA
MISO	G872	Hampton 345 kV Substation	875.0		875.0	119.6	13.7%	2015	3	ST	Coal	MI
PJM	V3-001	Burches Hill 500kV	750.0		750.0	150.0	20.0%	2015	5		Natural Gas	MD
PJM	R36	Bethany 138kV	450.0	90.0		0.0		2015	6	WT	Wind	DE
		2015	13,348.0	754.0	5,021.0	910.8						
PJM	V4-045	Peach Bottom	320.0		320.0	64.0	20.0%	2015	10	ST	Nuclear	PA
		2016	320.0	0.0	320.0	64.0						
MISO	G867	Fermi Nuclear Plant	1,563.0		1,563.0	1,563.0	100.0%	2017	3	ST	Nuclear	MI
PJM	V2-042	Calvert Cliffs 500kV	1,640.0	1,640.0		0.0		2017	6	ST	Nuclear	MD
		2017	3,203.0	1,640.0	1,563.0	1,563.0						
		2018	0.0	0.0	0.0	0.0						
PJM	R01	Susquehanna	800.0		800.0	160.0	20.0%	2018	10	ST	Nuclear	PA
PJM	R02	Susquehanna	800.0		800.0	160.0	20.0%	2018	10	ST	Nuclear	PA
		2019	1,600.0	0.0	1,600.0	320.0						
				Cumulative		Cumulative						
			Planned	Planned	Conceptual	Conceptual						
		2011	6,449	6,449	1,097	1,097						
		2012	4,074	10,523	644	1,741						
		2013	2,436	12,959	419	2,160						
		2014	381	13,340	370	2,530						
		2015	754	14,094	911	3,440						
		2016	0	14,094	64	3,504						
		2017	1,640	15,734	1,563	5,067						
		2018	0	15,734	0	5,067						
		2019	0	15,734	320	5,387						