DEMAND RESOURCE SATURATION ANALYSIS

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I PURPOSE

The purpose of this study is to evaluate the reliability value of Demand Resources (DR) in the PJM Region. Initiation of the study was prompted by the recent increases in the amount of DR committed in PJM, coupled with the limited interruption requirements for DR. This study determines the amount of DR at which its reliability value saturates under the current requirements regarding the number and duration of interruptions.

II BACKGROUND

PJM’s first demand side management program, known as Active Load Management (ALM), was implemented in 1991. Its purpose was to allow LSEs to reduce their capacity obligations by registering interruptible load customers that would contractually commit to interrupt their load during peak demand periods. The call for the interruption was at the command of PJM Operations and verification and compliance reviews were performed at the end of each summer.

The conceptual basis for ALM was that the customers’ commitment to interrupt during peak demand periods eliminated the need for those customers to procure generation capacity for the interruptible portion of their load. PJM stakeholders recognized that this premise was valid only if ALM customers (that committed no capacity to PJM) were interruptible over all loss of load risk periods so that their demand did not contribute to PJM’s loss of load probability (LOLP). To ensure this assumption was valid, PJM examined load duration curves for the then MAAC region. The result of this analysis was to establish the following requirements for qualifying an interruptible load program as ALM:

- Customers must be interruptible for up to ten times per summer
- Each interruption could be for up to six hours over the 1200-2000 time period of all summer weekdays
- The amount of ALM was limited to 5% of the forecasted unrestricted peak load for each zone

Based on updated analysis performed in 1995, the limit on ALM was raised to 7.5% of the RTO forecasted unrestricted peak load. Since 1995, the 7.5% limit and the requirement for ten interruptions per summer have been verified annually in the Installed Reserve Margin (IRM) Study. The actual amount of ALM in PJM has varied from about 1% to 4% over the 1991–2006 period and the ALM/DR limit has remained at 7.5%.

The amount of Demand Resources (including both DR and Interruptible Load for Reliability) has increased dramatically in recent years. The amount of DR in PJM was 1,677 MW in 2006/2007 and is projected to be over 8,500 MW in 2010/2011 (a fivefold increase). The corresponding increase in DR as a percent of load has been from 1.2% in 2006/2007 to 6.3% in 2010/2011. As the actual amount of DR in PJM approaches the limit of 7.5%, it is necessary to re-examine the determination of the limit and the DR interruption requirements that impact it.

III RTO ANALYSIS

PJM has more sophisticated analytical tools now than were available in 1995 when the issue of DR saturation was last investigated. Specifically, PJM now has a load forecasting tool that can produce a distribution of expected daily peaks. Because DR is implemented on a daily basis, this improved analytical capability allows for a more robust examination of the probability of implementing DR a given number of times over the summer period.

This study assesses the reliability value of DR given its two interruption requirements (ten interruptions per year and a six hour duration per interruption). Each of these requirements was investigated separately and the methodology and results are described below.

Ten Interruption Requirement

The general approach was to convolve the daily peak load distributions from the top 20 summer load days with the available capacity distribution to determine the frequency with which reserves would drop below a given threshold that would, in turn, trigger implementation of DR. This required development of a load and a capacity model.

Load Model:

1. The 2013 summer forecast distributions are obtained for the 20 CP (coincident peak) days from the 2009 load forecast. There are 481 scenarios, each representing a particular weather pattern (13 scenarios from each of 37 historical weather years). For a given weather scenario, the CP1 day represents the highest load forecasted for the summer of the forecast year. The CP2 day represents the 2^{nd} highest load forecasted, etc.

   Note: At the time the 2009 forecast was developed, ATSI was not included.

2. The median load value from the CP1 day corresponds to the 50/50 forecasted peak for the RTO in 2013/14. The 20 CP distributions are per-unitized on the

median of the CP1 day peak. In other words, the ratio of each of 481 x 20 loads to the median forecast peak is calculated. Using the ratio calculated, the 481 x 20 loads can be re-evaluated for any forecasted peak while preserving the shape of the original distributions. This allows the 20 CP day distributions to be shifted up or down by altering the seasonal peak load.

Capacity Model:

3. The PJMRTO cumulative capacity probability table from the 2009 IRM Study is used. The cumulative capacity probability table represents the distribution of available capacity each week. Available capacity is that generation that is not expected to be on a forced, maintenance or planned outage. The capacity distribution from week 10 (the peak week in the 2009 IRM Study for DY 2013/2014) is assumed to be constant for the entire period of 20 CP days. This assumption is made because there are no planned or maintenance outages over the summer period and the generator EFORd's are modeled as constant across the Delivery Year.

4. DR is assumed to be a 100% available resource that is available to assist the system whenever PJM operating reserves fall below a certain margin. The operating reserve is thus the margin between load and available capacity at which DR is expected to be invoked. An operating reserve margin of 1,300 MW is assumed for the RTO. This value is documented on page 11 of PJM Manual 13 and represents the RTO's synchronized/spinning reserve requirement that is based on the loss of the largest PJM generating unit.

Analysis:

5. Using the normalized distributions from Step 2, and the cumulative capacity probability table from Step 3, the LOLE is calculated for each of the 481 x 20 loads and aggregated. The peak load is iteratively increased until the Installed Reserve Margin (with no DR assumed) of 15.3% is established. 15.3% is the approved IRM for the 2013/2014 DY and is used by RPM to procure capacity resources for the RTO. This solved case forms the base case. Note: LOLE is always calculated at zero margin, i.e. load exceeds available capacity (including DR).

6. The 20 CP days from each of the 481 scenarios are derived from various weather patterns that simulate the need for invoking DR. At the assumed operating reserve margin, the following occur:

    a. If the margin between load and an available capacity state is greater than the operating reserve, no Loss of Load (LOL) occurs and no DR is invoked.

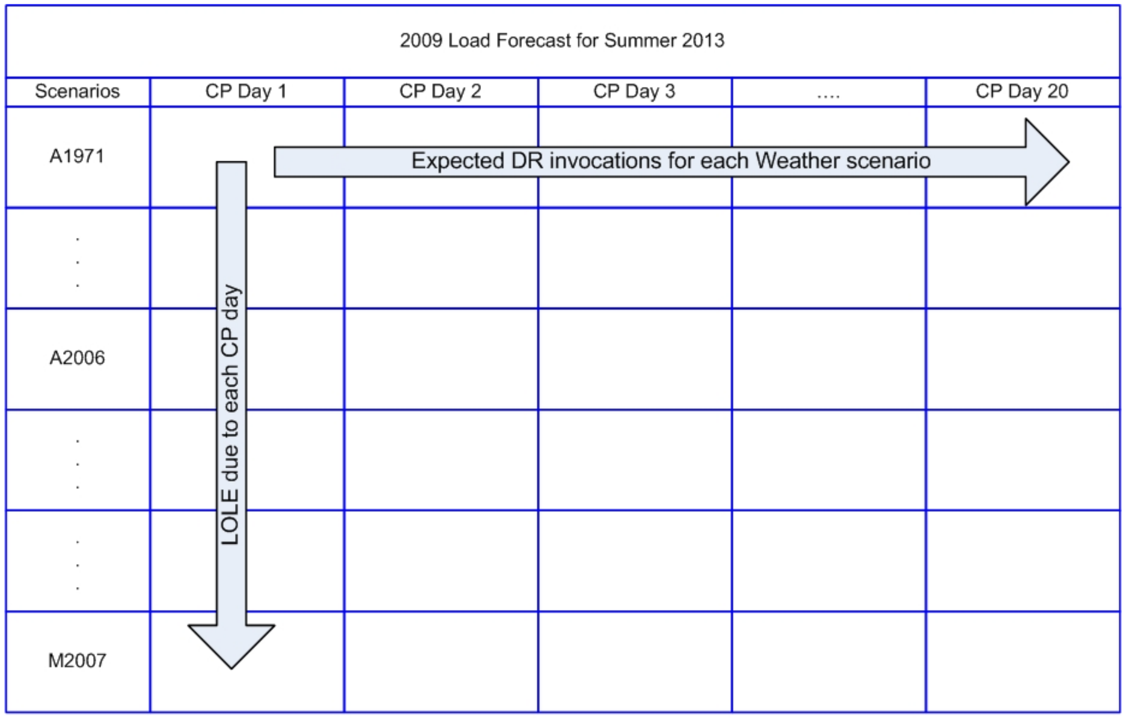
    b. If the margin between load and an available capacity state is less than the operating reserve, DR is invoked if available. No LOL occurs until the margin becomes less than or equal to zero. For each of the 20 CP days, the first instance (or capacity state) in which the margin falls below the operating reserve is used to determine the probability DR will be invoked on a particular day. For a CP day, DR can be invoked with a probability between zero and one depending on the capacity state at which the margin falls below operating reserve. For example, if (Capacity-load) <= operating reserves for all capacity states, the probability of DR invocation on that day is 1. Alternatively, if (Capacity-Load) > operating reserves for all the capacity states, the probability of DR invocation is zero. The probability of DR invocation is calculated for all 20 CP days in a weather scenario and is then summed. This sum represents the expected number of DR invocations in that scenario.

c. If, after invoking DR, the margin becomes less than zero for certain states, LOL occurs. The LOLE is aggregated for each CP day across all scenarios.

7. Using the 1,300 MW operating reserve margin, the amount of DR is progressively increased. The increase in DR is modeled as 100% available generation and the additional DR replaces an equal amount of generation resources so that the 15.3% reserve margin is held constant. Thus, as the amount of DR increases in the system, more generation is displaced and also the expected number of times DR is invoked increases.

8. A histogram of the expected DR invocations from the 481 scenarios is developed for each level of DR penetration. The histogram represents the frequency with which DR is implemented X number of times as X is varied from zero to 20.

Figure 1 below illustrates Step 5 - Step 8 for a given level of DR penetration.



- LOLE due to all 20 CP days is summed to calculate Total LOLE.
- Expected DR invocations for all 481 weather scenarios are used to create a Histogram

FIGURE 1

<u>Results</u>

The histogram described in Step 8 above can be aggregated into a cumulative probability curve that represents the likelihood that DR is implemented X or fewer times. That aggregation is depicted in Figure 2 below for ten or fewer interruptions:

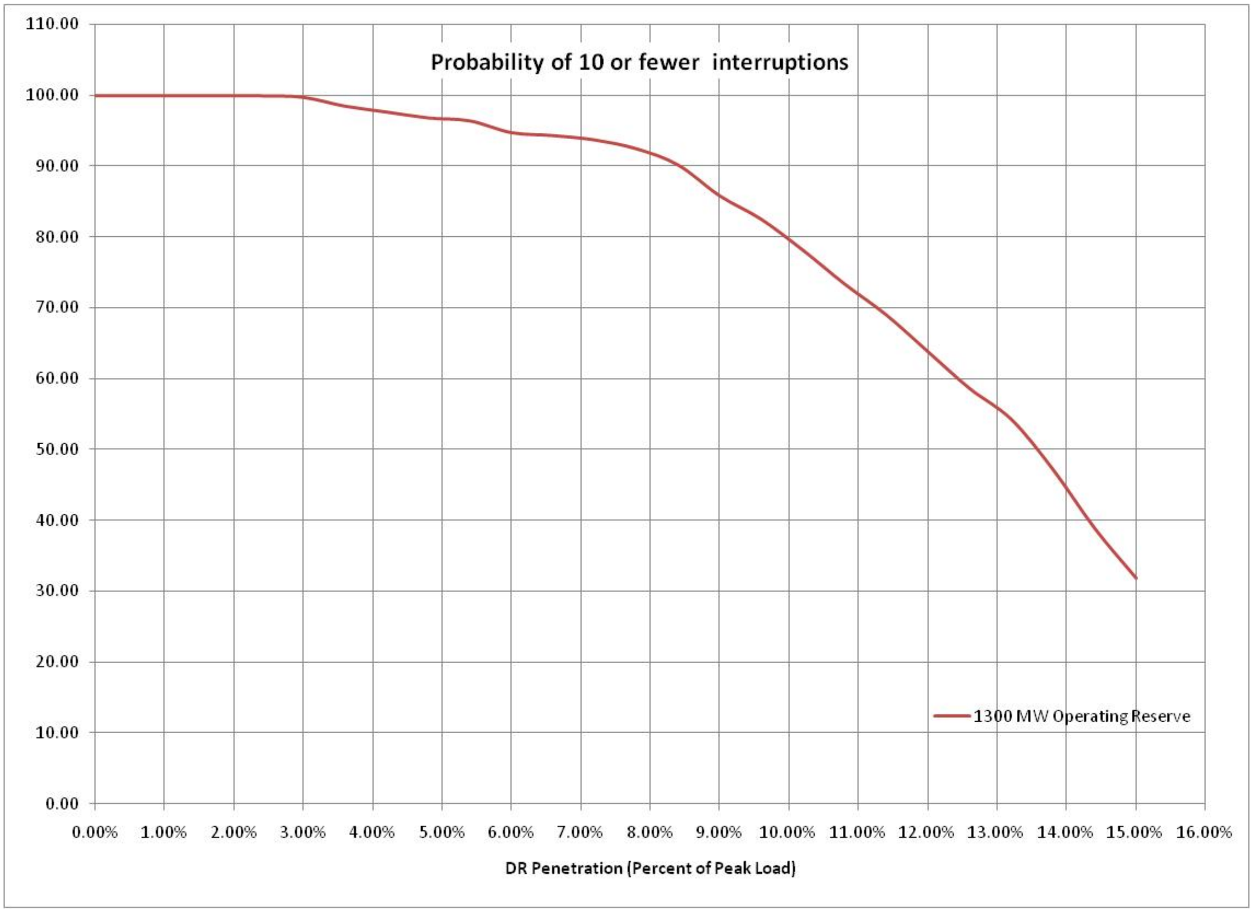


FIGURE 2

Figure 2 is based on a PJM case modeled at the 15.3% IRM reserve level and DR invocation is assumed whenever the operating reserve margin drops below 1,300 MW. Each DR invocation is counted as one event, regardless of the amount by which reserves drop below the 1,300 MW margin. This assumption is consistent with PJM operating practice and the practical reality of emergency conditions. PJM Operations calls for DR several hours in advance of the actual need when the peak load for that day is not known. Typically, PJM Operations does not have the need to call for the amount of DR that would restore reserves exactly to the 1,300 MW margin. Rather, on a typical PJM emergency day, all the DR in the affected area is invoked.

Figure 2 shows the likelihood that ten or fewer DR interruptions are needed as the amount of DR is increased across the horizontal axis. For instance, if DR were only 3% of the peak load, there is virtually a 100% chance that DR would be invoked 10 or fewer times (or a 0% chance it would need to be invoked more than 10 times). As the amount of DR increases, the probability of invoking DR ten or fewer times decreases (or, put another way, the probability of needing DR more than ten times increases).

Based on the information in Figure 2, engineering judgment must be applied to choose a DR penetration level at which PJM is comfortable that the probability of needing more than ten interruptions is not too large. A reasonable DR limit might be 8.5%, which is the point at which there is only a 10% chance that more than ten interruptions are needed (or, as indicated in Figure 2, a 90% chance of needing ten or fewer interruptions).

Sensitivity study results indicate that if the operating reserve margin were increased or decreased from the 1,300 MW level assumed in the base case, the DR saturation point would shift by a roughly equal MW amount in the opposite direction. For example, if the operating reserve margin at which DR is implemented were decreased to 1,000 MW, the DR saturation point would increase by approximately 300 MW.

Figure 2 is based on the current PJM requirement of ten interruptions. Figure 3 below illustrates the same case under the assumption of five or fewer and 15 or fewer interruptions.

FIGURE 3

The red curve in Figure 3 is the same as the curve in Figure 2. (Both are based on ten or fewer interruptions.) The green curve in Figure 3 shows the probability of invoking DR 15 or fewer times as the amount of DR is increased across the horizontal axis. So, for example, if the 90% threshold were applied, DR could be about 11% of the forecasted unrestricted load. 11% DR would be the level at which there is only a 10% chance of requiring more than 15 interruptions. Figure 3 therefore illustrates that, if the interruption requirement were increased from 10 interruptions to 15, the limit on DR could be increased from 8.5% to 11% based on the same 90% confidence threshold.

Six Hour Duration Requirement

The second area of investigation concerns the six hour duration requirement currently applicable to DR. The intent of the DR program is to shave the daily peak load, not to shift the peak to an hour outside the six hour DR window. If the DR amount increases to a certain level, however, implementing DR could have the effect of shifting the daily peak to an early afternoon or evening hour. If this occurred, the daily peak would not be reduced by the full amount of DR. This concept is illustrated in Figure 4 below:

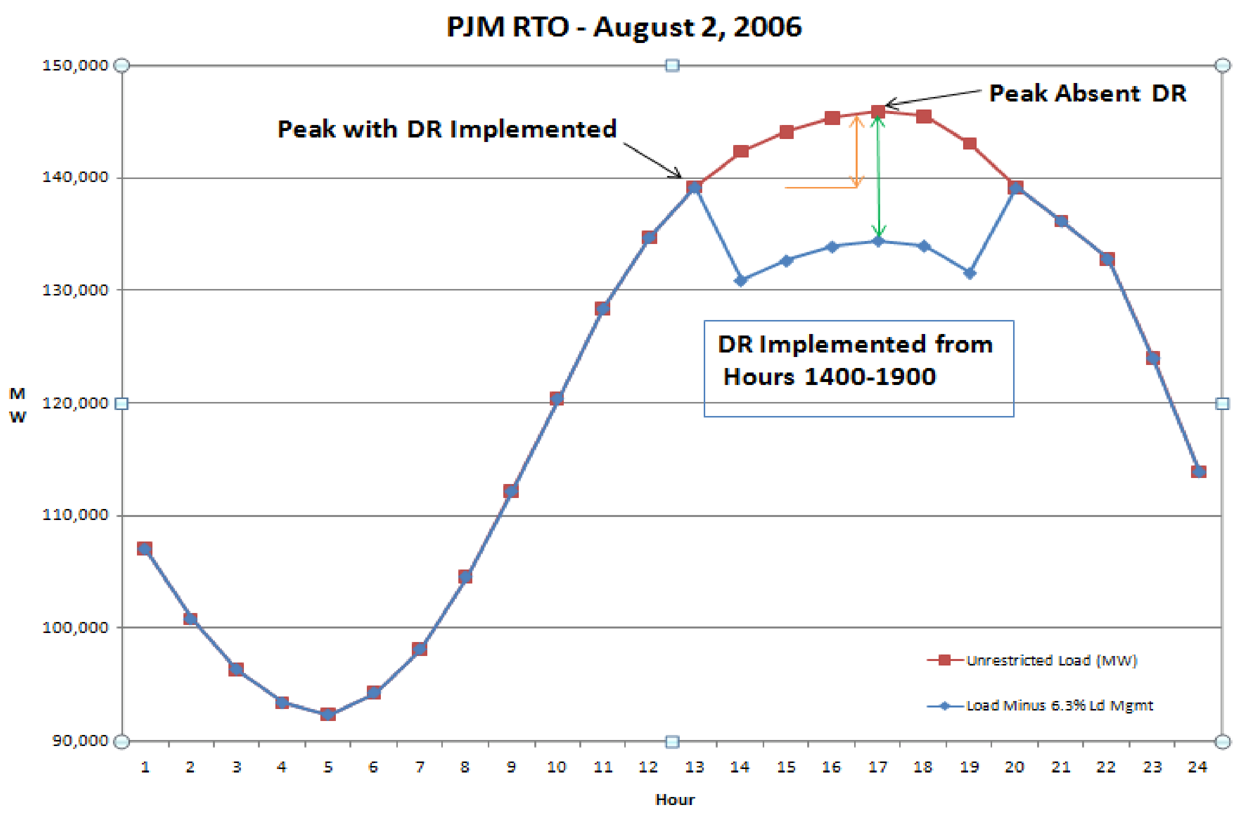


FIGURE 4

Figure 4 shows the hourly load curve from PJM's all-time peak day of August 2, 2006. The red curve shows the unrestricted load. If DR had been implemented over the highest six load hours of that day, the metered load would have followed the blue curve. (In this example, DR is assumed to be 6.3% of the weather-normalized peak. A 6.3% DR level is projected for the 2010/2011 Delivery Year.) As illustrated in the figure, the impact of implementing DR is to shift the daily peak to 1300 hours. As a result, the reduction in the daily peak (the vertical orange line) is less than the amount of DR implemented (the vertical green line).

To ensure the daily peak is reduced by the full amount of DR, the DR interruption window needs to be expanded to ensure that the peak of the day still falls within the DR interruption window. Figure 5 evaluates this issue for PJM's all-time peak day of August 2, 2006. The figure shows that the DR interruption window would need to be expanded to ten hours to ensure that the daily metered peak still falls within the DR window after DR is fully implemented. The assumed amount of DR for this analysis was 8.5% of the unrestricted load. The 8.5% level was selected based on results from the ten interruption investigation described in a previous section of this report.

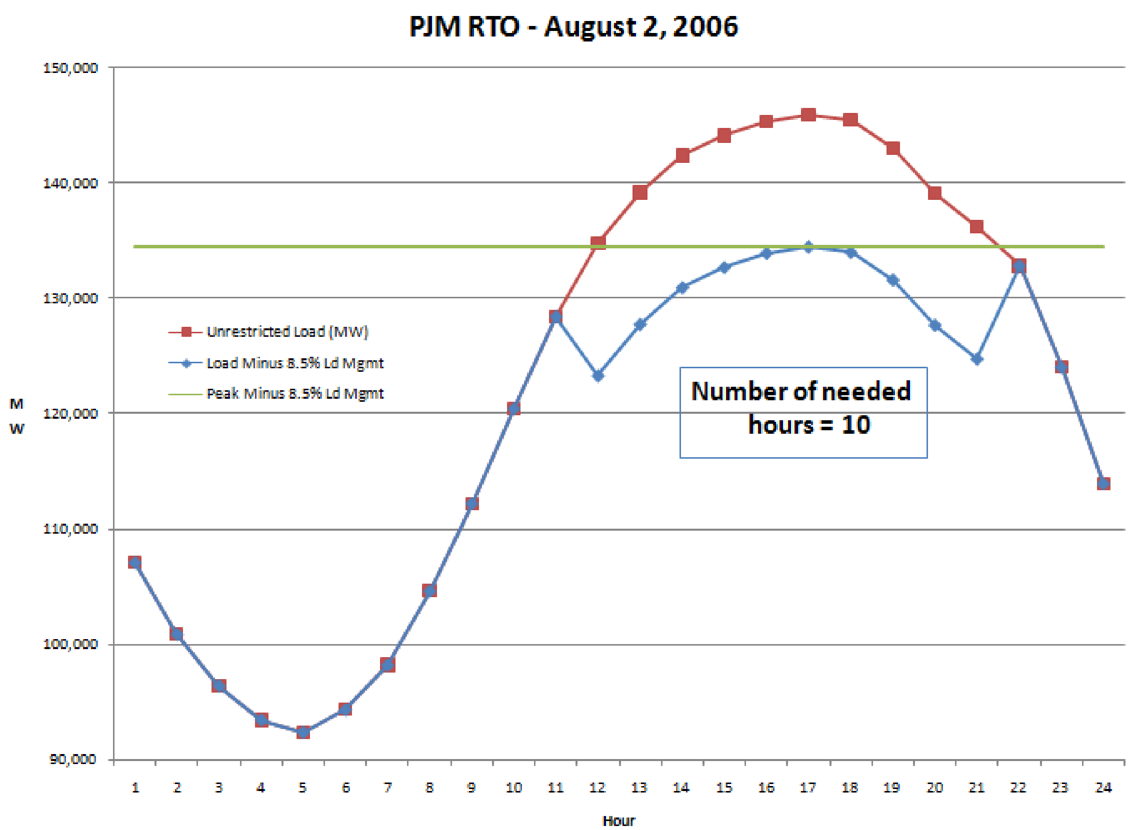


FIGURE 5

Figure 5 indicates that a ten hour DR interruption window is required for this particular day. The goal is to ensure that the green horizontal line is the metered peak. Therefore, any red data point falling above the green line would need to be reduced by implementing DR. There are ten red data points above the green line, so the interruption window, for this particular day, needs to be ten hours.

The required DR window can vary based on the particular load day being examined. This issue was investigated for each of the PJM annual peak load days from 2005-2009 and for any load day over that period on which the unrestricted peak was greater than the 50/50 weather-normalized peak load. These days would be most likely to require invocation of DR. In all these cases, the amount of DR was assumed to be 8.5% of the unrestricted peak load. For each day, the required DR interruption window was determined based on the same approach used in Figure 5. The results are summarized below in Table 1. (The load percentile column indicates where the load falls on the peak day (1CP) load distribution of that particular year.)

REQUIRED DR INTERRUPTION WINDOW FOR SELECTED LOAD DAYS

Date		Load Percentile	Required DR Interruption Window
7/26/2005	Annual Peak	55/45	9 hours
8/3/2005		55/45	9 hours
7/17/2006		70/30	9 hours
7/31/2006		65/35	10 hours
8/1/2006		95/5	10 hours
8/2/2006	Annual Peak	95/5	10 hours
8/3/2006		60/40	9 hours
8/8/2007	Annual Peak	70/30	8 hours
6/9/2008	Annual Peak	20/80	10 hours
8/10/2009	Annual Peak	20/80	9 hours

TABLE 1

These results indicate that, if the DR limit were raised to 8.5%, the duration window should be expanded to ten hours to ensure that the daily peak is reduced by the full amount of implemented DR.

IV LDA ANALYSIS

The RTO analysis described in Section III examined the likelihood of implementing DR across the RTO due to an overall insufficient level of generation resources. DR may also be implemented to relieve local reliability problems specific to an individual Locational Deliverability Area (LDA).

The three LDAs of primary interest in this study were MAAC (consisting of the PJM Mid-Atlantic zones), Eastern MAAC (consisting of the PSE&G, JCP&L, PECO, AE, DPL and RE zones) and Southwestern MAAC (consisting of the PEPCO and BG&E zones). The ten interruption analysis procedure described above for the RTO was applied to each of these three LDAs with two modifications:

1. LDA reserves were set to the LDA's internal generation plus its Capacity Emergency Transfer Limit (CETL). This is the maximum amount of reserves expected to be available to the LDA during a local capacity emergency.
2. The operating reserve margin at which DR was assumed to be implemented was zero MW. This approach assumes that DR is initiated for LDA related problems only at the point of avoiding an actual loss of load event (or a negative reserve margin).

The results of this analysis for MAAC, EMAAC and SWMAAC are graphically depicted in Figures 6, 7 and 8, respectively. Each figure shows the probability of requiring five or fewer, ten or fewer and 15 or fewer DR interruptions as the amount of DR is increased across the horizontal axis.

FIGURE 6: MAAC

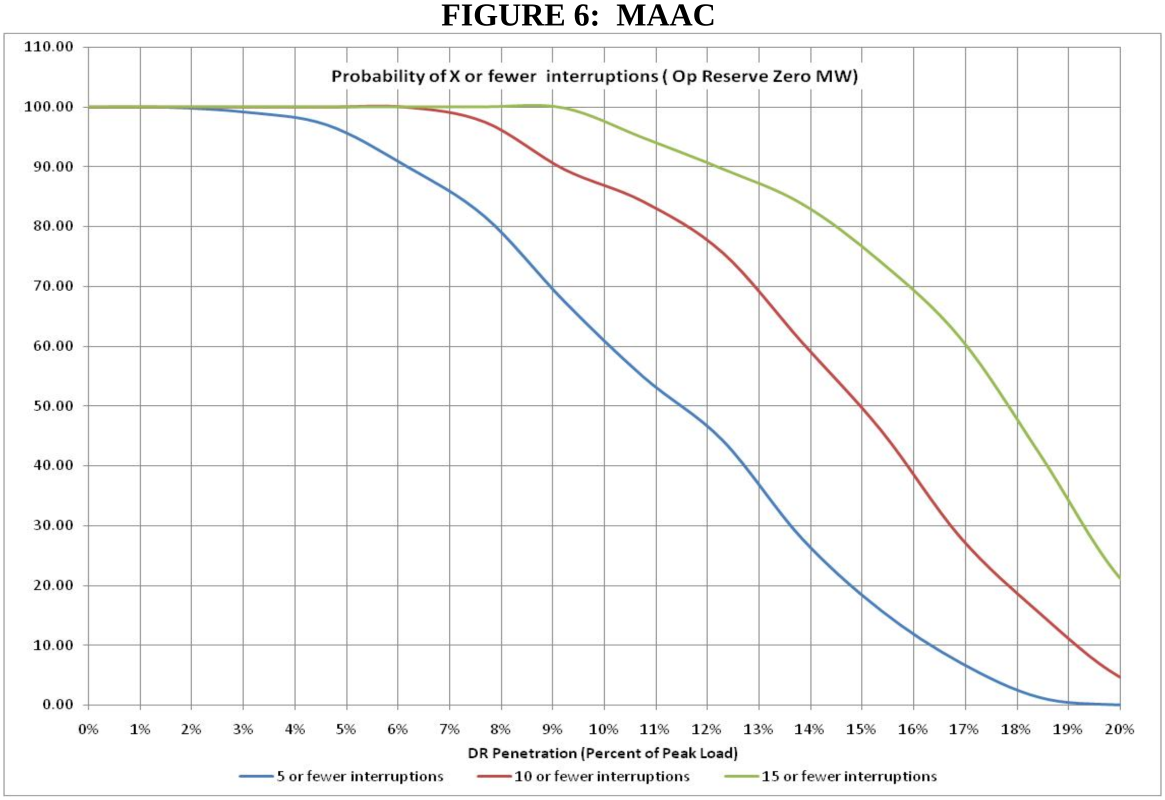


FIGURE 7: EASTERN MAAC

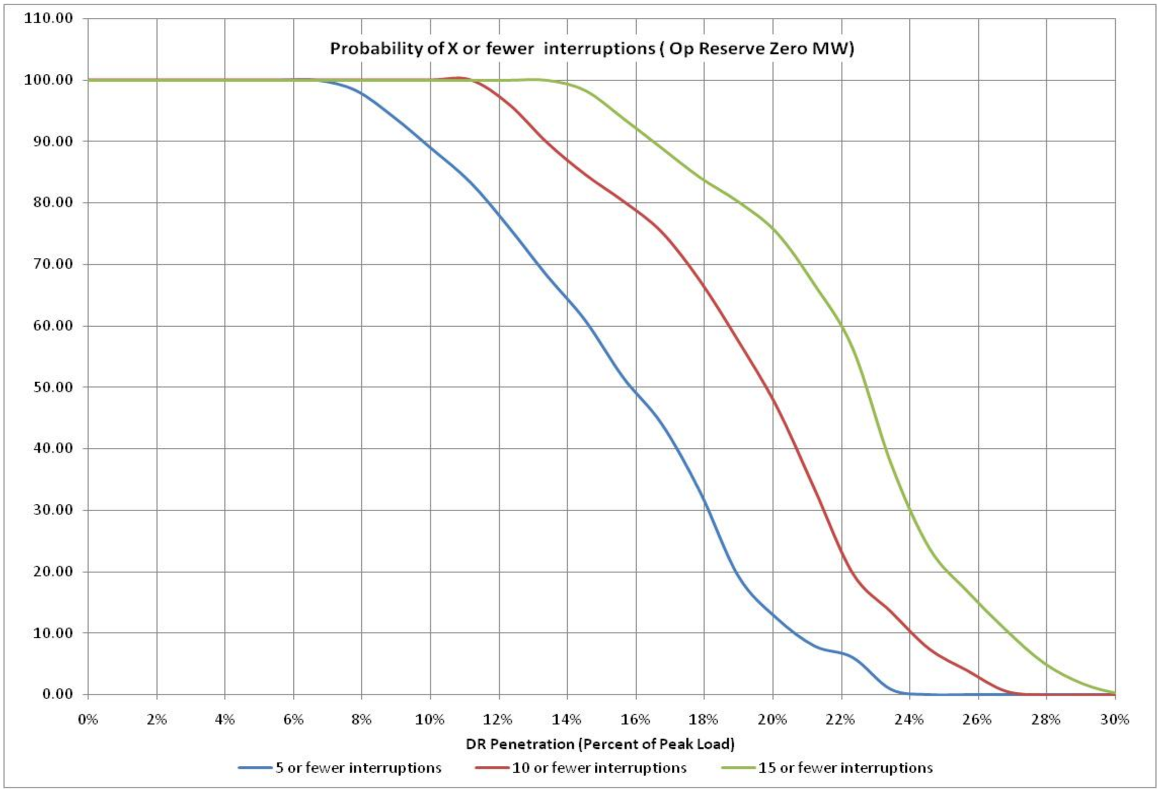


FIGURE 8: SOUTHWEST MAAC

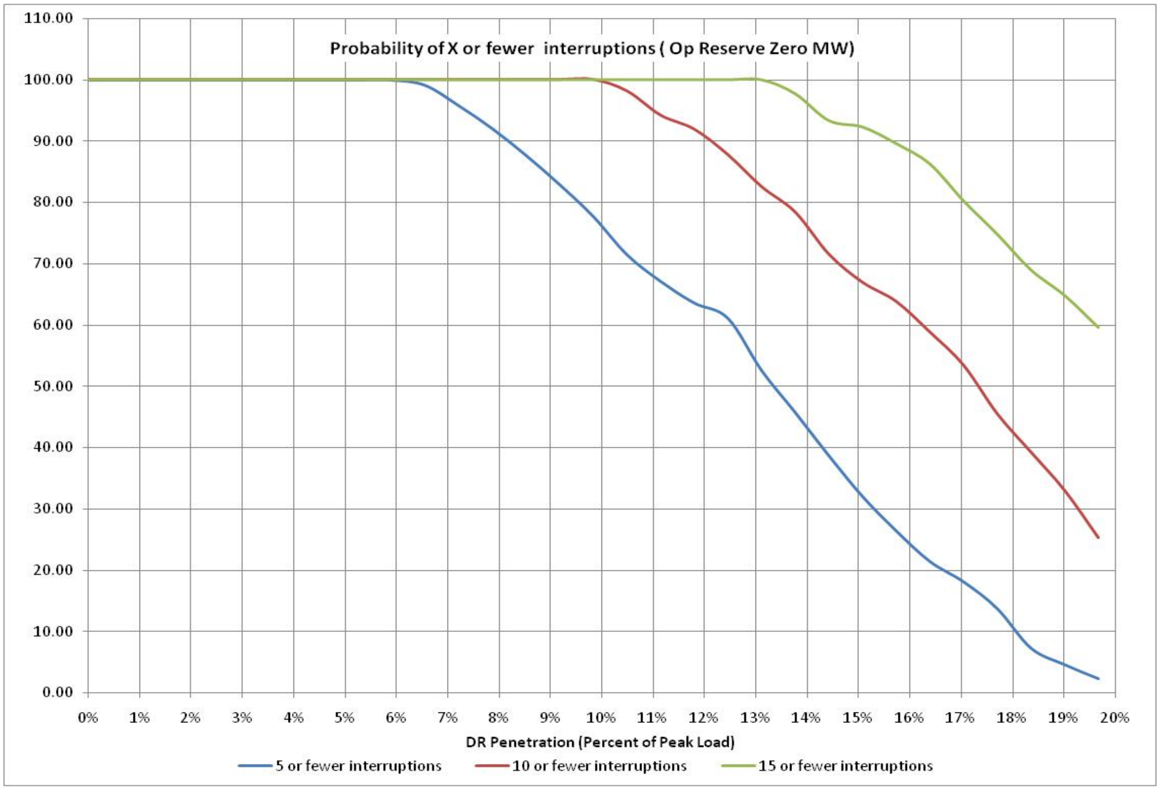


Figure 6 indicates that, based on the same 90% confidence level used in the RTO analysis, the DR penetration level in MAAC should be limited to 9.0% of the forecasted unrestricted MAAC load. The 9.0% value is based on the current requirement of ten interruptions (the red curve in the figure). The "90% confidence" DR limits for Eastern MAAC and Southwestern MAAC are 13.5% and 12.0% based on Figures 7 and 8, respectively.

The green colored curves in Figures 6, 7 and 8 indicate that the DR penetration limits for the three LDAs could be increased if the interruption requirement were raised to 15 per year. The "90% confidence" limit under a 15 interruption per year requirement would be 12.0% for MAAC, 16.5% for Eastern MAAC and 15.5% for Southwestern MAAC.

The DR penetration levels in the LDA analyses are expressed as a percentage of each LDA's non-coincident peak load (NCP). The RPM auctions are conducted using PJM coincident peak loads, so the 9.0%, 13.5% and 12.0% values described above must be converted to a coincident peak load (CP) basis. That conversion is illustrated in Table 2 below.

10 or fewer interruptions					
LDA	DR limit (% of NCP)	NCP Load (MW)	DR Limit (MW)	CP load (MW)	DR Limit (% of CP)
PJMMA	9.0%	64593	5813	62608	**9.3%**
EPJMMA	13.5%	35444	4785	34273	**14.0%**
SPJMMA	12.0%	15244	1829	14715	**12.4%**

TABLE 2

The NCP load values in Table 2 are from Tables B-1, C-3 and C-4 in the 2010 PJM Load Forecast Report and the CP values are from Table B-10 in the same report. All load values are for the 2013/2014 Delivery Year. The rightmost column of Table 2 indicates that the DR limits for MAAC, Eastern MAAC and Southwestern MAAC on a PJM coincident peak load basis are 9.3%, 14.0% and 12.4%, respectively. These LDA limits would need to be observed in addition to the RTO-wide DR limit of 8.5% described in Section III of this report.

The DR limits, assuming a 15 interruption per year requirement, are converted to a PJM coincident peak load basis in Table 3 below.

15 or fewer interruptions					
LDA	DR limit (% of NCP)	NCP Load (MW)	DR Limit (MW)	CP load (MW)	DR Limit (% of CP)
PJMMA	12.0%	64593	7751	62608	**12.4%**
EPJMMA	16.5%	35444	5848	34273	**17.1%**
SPJMMA	15.5%	15244	2363	14715	**16.1%**

TABLE 3

It is important to note that the LDA analysis results are very sensitive to the CETL used to determine the LDA reserve margin. CETL values can change significantly from year to year based on inputs such as the load forecast, generator retirements and the completion or deferral of planned transmission upgrades. As a result, the LDA DR percentage limits could also change significantly from year to year.

V CONCLUSION

Given the current interruption requirements applicable to DR, these study results indicate that the reliability value of DR saturates at an 8.5% penetration level for the RTO. The 8.5% level is based on acceptance of a 90% degree of certainty that DR would not need to be implemented more than ten times in a single year. The study indicates that the DR saturation level would increase to 11% if the interruption requirement were raised from ten to 15 interruptions per year. If an 8.5% RTO limit for DR were established, the interruption window should be expanded to ten hours to ensure the daily peak is not shifted to an off-peak period.

The LDA analysis results indicate that, under current interruption requirements, the reliability value of DR saturates at 9.3% for MAAC, 14.0% for Eastern MAAC and 12.4% for Southwestern MAAC. The LDA analysis considered only DR interruptions that were required to address local, not RTO-wide, reliability problems.

Given these findings and the current DR interruption requirements, PJM recommends the following:

1. The amount of DR RTO-wide should be capped at 8.5% of the forecasted unrestricted peak.

2. The amount of DR in MAAC, Eastern MAAC and Southwestern MAAC should be capped at the levels indicated in the table below. The caps are expressed as a

percentage of each LDA's forecasted PJM coincident peak. It is important to note that these caps are based on each LDA's CETL for the 2013/2014 Delivery Year. The caps could change significantly for other Delivery Years as the CETL is impacted by factors such as generator retirements and the completion or deferral of planned transmission upgrades.

Proposed DR Limits for 2013/14 Delivery Year

LDA	DR Limit
MAAC	9.3%
Eastern MAAC	14.0%
Southwestern MAAC	12.4%

3. Any capacity procured in excess of the IRM or in excess of an LDA's Reliability Requirement could also be DR. This DR would not count toward the cap.

4. The DR interruption window should be expanded from six to ten hours to ensure that the daily peak is reduced by the full amount of implemented DR.