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Modeling of Emergency Operating Procedures (EOPs) and Demand Resources (DR) in External Areas in IRM Studies

Background

In establishing installed reserve margin (IRM), the power systems in the Northeast design their system to the “once in ten year” or “one day in ten year” criterion which is described below for NPCC, NY and PJM:

NPCC Areas: The probability (or risk) of disconnecting **firm load** due to resource deficiencies shall be, on average, not more than one day in ten years as by studies conducted for each Resource Planning and Planning Coordinator Area. Compliance with this criterion shall be evaluated probabilistically, such that the loss of **load** expectation (LOLE) of disconnecting **firm load** due to resource deficiencies shall be, on average, no more than 0.1 day per year. This evaluation shall make due allowance for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or **load** relief from available operating procedures.

New York: The NYSRC shall establish the IRM requirement for the NYCA such that the probability (or risk) of disconnecting firm load due to resource deficiencies shall be, on average, not more than once in ten years. Compliance with this criterion shall be evaluated probabilistically, such that the loss of load expectation (LOLE) of disconnecting firm load due to resource deficiencies shall be, on average, no more than 0.1 day per year. This evaluation shall make due allowance for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring control areas, NYS Transmission System transfer capability, and capacity and/or load relief from available operating procedures. To calculate its reserve requirement NY uses the GE Multi-Area Reliably Simulation (MARS) model.

PJM: The PJM Reserve Requirement is defined to be the level of installed reserves needed to maintain the desired reliability index of ten years, on average, per occurrence (loss of load expectation of one occurrence every ten years) after emergency procedures to invoke load management. The Probabilistic Reliability Index Study Model (PRISM) program is the principal tool used to calculate the PJM Reserve Requirement. The PJM Reserve Requirement is calculated using a PRISM two-area model; Area #1, the entire PJM control area without internal transmission constraints and, Area #2, a composite World representation consisting of parts of SERC, RFC, MISO and NPCC. It is not a Monte Carlo based model nor is it capable of modeling transmission capability between PJM RTO zones or between the external control areas but models tie capability between the PJM-RTO area and the external areas. The PJM Installed Reserve Margin value is used in the determination of the Forecast Pool Requirement[1] and DR factor[2]. Similar to NPCC Areas, PJM is required to submit evidence that it is in compliance with its one day in 10 year criterion.

The power systems in the Northeast utilize emergency operating procedures to mitigate shortages or scarcity of conventional generating resources which are generally implemented after the declaration of a generation emergency to avoid loss-of-load (LOL) events. These procedures could include supplements to conventional generation, load control measures such as reducing interruptible loads/demand response, making public appeals to reduce demand, and/or implementing voltage reductions. Other measures could include calling on generation available under emergency conditions such as emergency purchases, and/or reducing operating reserves. Each system has its protocols has to what and when these procedures are implemented. In calculating its reserve requirements each system also makes a determination as to which of these procedures, if any, are included in its system IRM calculation as provided for in the criterion.

For the purpose of this discussion only, these procedures will collectively be referred to or defined as scarcity resources which are resources that are utilized or deployed after the declaration of a generation emergency to avoid a LOL event when conventional generating resources become scarce or unavailable. Scarcity resources such as NY's Special Case Resources (SCRs), ISO-NE's Active DR, and PJM's Pre-Emergency DR can be called in anticipation or a forecast of being short reserves or generating capacity while others scarcity resources such as PJM's emergency DR, voltage reduction and reduction of reserves generally require an emergency declaration. These pre-emergency resources are not considered EOP steps since they can be implemented prior to the declaration of a generation emergency.

[1] Forecast Pool Requirement (FRR) is defined as the reserve requirement in unforced capacity terms. The FPR is defined by the following equation: FPR = (1 + IRM) * (1 – PJM Avg. XEFORd).

[2] The DR Factor is a measure of the reliability value of demand resources and energy efficiency resources. The load carrying capability of these resources is divided by the total amount of (DR+ EE) to yield the factor.

Prior practice in NY, in accordance with Policy 5, has been to include NY's scarcity resources in its IRM calculation but to exclude the scarcity resources in neighboring systems from the calculation. This can result in LOLEs in external areas that are higher than criterion and raised concerns as the neighboring systems are now more dependent on scarcity resources such as DR. The organized power markets systems in the Northeast have developed robust DR markets. This is especially true in PJM where the exclusion of the scarcity resources appears to result in a LOLE that is much higher than the criterion of 0.1 days per year. For example, the 2015-16 IRM Study showed that without representing any DR programs, the PJM LOLE was 0.88 days per year. The base case represented two non-EOP types of DR, Extended and Annual (total of 5,617 MW) – for this case the PJM LOLE was 0.23 days per year. These results engendered much concern and discussion among ICS members.

As result of the concern raised by the exclusion of scarcity resources in PJM from the NYSRC IRM study, the ICS at its December 2014 meeting directed Messrs. Adamson and Adams to review Policy 5 first regarding the language for external area EOPs. From there, they were requested to assess neighboring control areas processes to establish their IRM and determine the appropriate method for the NYSRC to model neighboring EOPs, if necessary, for the 2016 IRM study. At the January meeting the study group was expanded to include Greg Drake and Syed Ahmed.

The study group developed a scope of work which is attached as Appendix A with three primary objectives as follows:

1. Examine the present policy of not representing in the IRM study the EOPs that are available in each neighboring Control Areas (CA). Recommend changes for each, if warranted.

2. Establish 2016 PJM DR forecast projections for different DR categories and determine which should be considered as EOPs.

3. Based on EOP recommendation in 1, recommend modeling of DR in Outside World Areas, specifically in PJM

The scope also identified a number of fact finding actions and questions. The balance of the report provides the results of the fact finding and questions, what conclusions can be drawn from them, as well as recommendations.

Findings and Observations:

The first task the study team undertook was to compile information regarding the amount of DR and EOP steps available in neighboring control areas. Capacity information was compiled by category of scarcity resource and in total as well as the extent the scarcity resources are included in IRM studies. Table I is a compilation of series of questions and answers which describes how NYCA neighboring control areas use EOPs and DR in establishing their IRM. Table II is a compilation of the DR and EOP steps in NY and the external CAs in terms of capacity by Category and in total and as a percent of the peak load. Also, DR is reported in total and the amount that is considered as an EOP step. Table III is compilation of all the EOP steps, excluding tie benefits or emergency purchases, identified in the external CA and indicates whether they are considered in the IRM study or not.

Table I

Emergency Operating Procedures (EOPs) and Demand Resources (DR) in the External Control Areas VS NY regarding Use in IRM Studies					
Question	**NY**	**NE**	**Ontario**	**Quebec**	**PJM**
Does the area include the LOLE benefits provided by emergency assistance or tie benefits (TB) in establishing their reserve margins?	Yes	Yes	No	Yes	Yes
Magnitude of benefit from latest study as a % and in MW?	8.9% 2,995.3	5.7% 1,624	n/a	n/a	1.9% 3,500 MW
Does the area include the LOLE impacts of its own EOP steps excluding reserves to zero (RTZ) and tie benefits (TB)?	Yes	Yes	No	Yes	No
Does the study include the LOLE benefits of EOP steps in neighboring areas?	No	Yes But does not include PJM	No	No	No uses two area model. Includes TB of 3500 MW in its IRM study
Is any DR considered as an EOP step?	No	Yes	No	Yes	No
Are EOP steps or DR considered directly in setting the IRM excluding RTZ and TB?	Yes	Yes	No	Yes	No

Table II

DR and EOP Steps Considered by Each Area in Reserve Margin/LOLE Calculation[8]					
DR/SCR	**NY**	**NE**	**Ontario**	**Quebec**	**PJM[7]**
Total DR/SCRs MW % of Peak	1132.4 MW 3.4%	2,852[9] MW 10.0%	567.4 2.5%	1,941 MW 4.4%	14,812[7] MW 9.2%
EOP Step	**NY**	**NE**	**Ontario**	**Quebec**	**PJM**
EDRPs % of Peak	86 MW 0.0%	-	-	-	-
5% manual voltage reduction % of Peak	62 MW 0.2%	-	-	-	-
5% remote voltage reduction % of Peak	441 MW 1.3%	432 MW 1.5%	-	250 MW 0.6%	-
Voluntary load relief[3] % of Peak	210 MW 0.7%	-	-	-	-
Thirty-minute reserve to zero % of Peak	655 MW 1.9%	625 MW 2.2%	-	500 MW 1.1%	2,765[7] MW
Ten-minute reserve to zero % of Peak	1,310 MW 3.8%	1,550 MW[4] 5.4%	-	700 MW[4] 1.6%	1,300[7] MW
Emergency purchases/TB % of Peak	2,995.3 MW 8.9%	1,624 MW 5.7%	-	1,100 MW[1] 2.5%	3,500[2] MW 1.9%
DR as an EOP step % of Peak	0 MW 0.0%	1,032 MW[6] 3.6%	-	1,941[5] MW 4.4%	-
Total of EOP steps % of Peak	6,429.3 MW 19.1%	5,263 MW 18.4%	-	4,491 MW 10.2%	7,565 MW 4.7%
Total EOP steps net of reserves % of Peak	4,464.3 13.3%	3,088 MW 10.8%	-	3,291 MW 7.4%	3,500 MW 1.9%

Table II Notes:

1) Based 2014 Quebec NPCC Comprehensive review which states that Quebec schedules emergency purchases of 1,100 MW for the winter only.
2) The 3,500 MW of Tie Benefits or as defined by PJM as capacity benefit margin (CBM) is specified in its Reliability Assurance Agreement
3) Includes voluntary industrial load curtailment, public appeals, etc.
4) Based on NPCC Long Range Adequacy Overview. Value is 125% of largest contingency. Based on the NE ICR report it suggest an LOLE event is recorded once reserves drop below 200 MW and appears this is the case for Quebec as well with a threshold of 250 MW
5) DR is Winter only as is the emergency purchase which is modeled as a planned purchase
6) Based on NPCC Long Range Adequacy Overview and consist of 294 MW of RT-EG and 738 MW of RT-DR
7) The PJM Reserve Requirement is defined to be the level of installed reserves needed to maintain the desired reliability index of ten years, on average, per occurrence (LOLE of one occurrence every ten years) after emergency procedures to invoke load management. DR is assumed to be a single, 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. However, the IRM is established using the PRISM program without considering DR. DR is incorporated after the IRM is set through a process identified as the "DR Reliability Target Analysis Procedures". The PJM IRM is set without utilizing any EOP steps except for tie benefits and implicitly allowing operating reserves to go to zero before an LOLE event is recorded.
8) A blank does not mean that the area does not have this procedure as an element of its emergency operating procedures. It only indicates that the procedure is not used in setting the reserve margin. See Table III below
9) ISONE's DR breaks down is approximately 55% passive and 45% active for 2015. Active demand resources are activated only when needed within 30 minutes of receiving ISO dispatch instructions when certain steps in OP 4: Action during a Capacity Deficiency are implemented. Passive demand resources are principally designed to save electricity use at all times. Examples include energy-efficiency measures, such as the use of energy-efficient appliances and lighting, advanced cooling and heating technologies, electronic devices to cycle air conditioners on and off, and equipment to shift electricity use to off-peak hours.

Table III

EOP Steps Excluding Emergency Purchases and MW Identified In Neighboring Areas for Summer 2015				
	New England	Ontario	Quebec	PJM
Interruptible Loads/DR	325 MW	528 MW	-	14,815 MW
Appeals/Curtailments	540 MW	188 MW		200 MW
Voltage Reduction	422 MW	477 MW	250 MW	2,201 MW
Real-Time EG	294 MW	-	-	-
No 30 Minute Reserve	625 MW	473 MW	500 MW	2,765 MW
No 10 Min Reserves	1,550 MW	945 MW	750 MW	1,300 MW
Total	3,756 MW	2,611 MW	1,500 MW	21,281 MW
Total Less Reserves	1,581 MW	1,193 MW	250 MW	17,217MW

Based on the information compiled during the fact finding process which includes the PJM presentation at the March 4 ICS meeting, the following observations can be made.

1. Two of the NPCC Areas (ISO-NE, Quebec) modeled by the NYSRC as an external CA in the IRM study plus NY include the LOLE benefits of EOP steps such as voltage reductions and emergency purchases in establishing their reserve margin. Quebec models their EOP steps for the winter period not summer. ISO-NE and Quebec EOP steps include DR while NYISO doesn't, although NYISO generally calls its SCR/DR when it expects to be short operating reserves day ahead.
2. One of the NPCC Areas (Ontario) has EOPs steps available but excludes them for the purpose of establishing their IRM.
3. PJM does not consider DR or EOP steps such as voltage reduction, public appeals in the PRISM model which is the modeling toll that is used in establishing the PJM-RTO IRM. However, as noted in note 7 in Table II, the PJM Reserve Requirement is defined to be the level of installed reserves needed to maintain the desired reliability index of ten years, on average, per occurrence (LOLE of one occurrence every ten years) after emergency

procedures to invoke load management. They identify 14,815 MW of load management as being available. Load management as a resource is procured through the PJM capacity auction. This total does not include any energy efficiency MW. Currently, a PJM DR provider can register their DR as either emergency or pre-emergency DR. Pre-emergency DR can be activated prior to the declaration of a major emergency in order to avoid the emergency situation. This category includes the extended and annual capacity that was modeled in the 2015 NYSRC IRM study and totaled 5,617 MW.

4. PJM DR whose UCAP value is determined by the DR reliability target analysis procedures participates in the capacity market. This procedure utilizes the PRISM program and program called CURTAIL. Its UCAP value and MW amount is determined in such a way that the LOLE of once in ten years is maintained at the approved reserve margin calculated with the PRISM program - i.e., the DR UCAP and MW amounts are calculated in such a way that calculated DR MW can be a one for one replacement to the capacity modeled in their IRM study.
5. In the NYSRC 2015 IRM modeling, the initial PJM LOLE value as noted above was well above 0.1 even though PJM determines their reserve margin to meet 0.1 without including DR or EOP steps except for allowing operating reserves to go to zero. The fact that the LOLE value for PJM in the NYSRC modeling was so high it was a concern discussed at the March 4 ICS meeting with PJM staff. It was unclear at the March 4 ICS meeting why the modeled portion of the PJM RTO had such a high initial LOLE. Subsequent to the ICS meeting it was determined that PJM's reserve margin based solely on installed generating capacity is projected to be 14.4% for the summer of 2015. This is below the required reserve of 15.6%. DR is makes up the difference plus provides a surplus. Therefore, modeling PJM with just its operable generating capacity which had been the practice prior to last year now results in much higher LOLEs then experienced in the past.
6. Another possible factor that puts upward pressure on the PJM LOLE is that the NYSRC utilizes the GE Monte Carlo simulation model that models transmission interfaces in the PJM-RTO region. The PJM sets their reserve margin based on a two area model, PJM is modeled in Area #1 and a composite World representation consisting of parts of SERC, RFC, MISO and NPCC less the Canadian systems is modeled in Area #2. No internal

transmission interfaces are modeled within either of the two areas. It is not a Monte Carlo based model and doesn't have the ability to model transmission capability between the PJM RTO zones or between the outside world areas but models tie capability between the two larger single areas. Whereas, the NYSRC models includes internal interface ties between zones and within the PJM-RTO. The PJM IRM assumption is that the PJM aggregate of generation resources can reliably serve the aggregate of PJM load. This assumption is validated through coordination with Capacity Emergency Transfer Objective (CETO) studies and shows that the generation resources modeled in the IRM study have passed PJM's load deliverability test.

7. As measured as a percent of the peak load, NY derives more LOLE benefit from the use of its EOPs than any of its neighboring control areas. This especially true for emergency purchases or tie benefits which are significantly greater than any of the other external CAs systems modeled in the IRM study based on the data compiled.
8. ISO-NE models neighboring control area EOPs in the MARS model when establishing its IRM. It was not clear from the documentation how they have the model set up to allow those OWA EOPs to benefit ISO-NE. The MARS model can be set up such the EOPs in say in POOL A can only be called for the benefit of POOL A but once POOL A activates the EOPs, any excess remaining above pool A's need can be shared with other POOLs depending on the transmission capability available.

Conclusions and Recommendations:

Based on the compiled information and observations, the study group makes the following recommendations to be implemented for the 2016-17 IRM Study:

1) New York's practice of not modeling the EOP steps in the external Control Areas which are modeled in its IRM study as reflected now in Policy 5, should be maintained. EOP steps are those procedures that require the declaration of generating emergency to be implemented. This conclusion is based the following considerations:
   a) Both PJM and Ontario establish their installed reserve margin without including EOP steps such as appeals, voltage reductions, etc. PJM also excludes DR resource while Ontario includes them in the IRM study. PJM

includes tie benefits in an amount equivalent to 1.9% of their peak while Ontario excludes tie benefits altogether. It would not be appropriate for NY to include EOPs steps in a neighboring area/pool in its IRM study when that area does not include it in their own IRM study.

b) Quebec EOPs are structured to provide load relief for their winter peak or supplement winter capacity and would not provide any benefits to a summer peaking system. In addition, the key limitation of resource benefits between NY and Quebec is the capability of the transmission ties between the two areas and modeling EOP steps/resources in Quebec would not have any material impact on NY's LOLE.

c) Based on NY isolated VS NY interconnected, NY "leans on the ties" as a percentage of its peak more than any other area in the Northeast. Modeling EOPs in neighboring areas will result in an even higher reliance on those LOLE reduction benefits.

d) Policy 5-8 indicates that EOPs are not represented in external control areas because "there are uncertainties associated with the performance and availability of these resources and the ability to deliver them to NYCA boundaries during a system emergency event, as well as recognition of other unknowns in the external control area modeling representation." Although, as a result of this analysis, we now have more clarity on neighboring EOP steps and indications that they would match NY step for step, uncertainties still remain as to how events will unfold in real-time. Given this ongoing uncertainty and analysis presented above the practice of not modeling EOP steps in OWAs in determining NY's IRM should continue.

2) If PJM's as found reserve margin is less than required and its LOLE is greater than 0.1, pre-emergency DR should be added until the system is close to or equal to but not better than 0.1 or the required reserve margin has been satisfied. This practice began last year and will address the concern regarding the high PJM-RTO LOLE that resulted from a significant decline in PJM's capacity margin. This approach satisfies the requirements established in Policy 5 for modeling external areas.

3) Policy 5 language in section 3.5.6 on page 15 will require review and updating as needed based on the findings in this document.