New York State Reliability Council

Installed Reserve Margin

Study Guide

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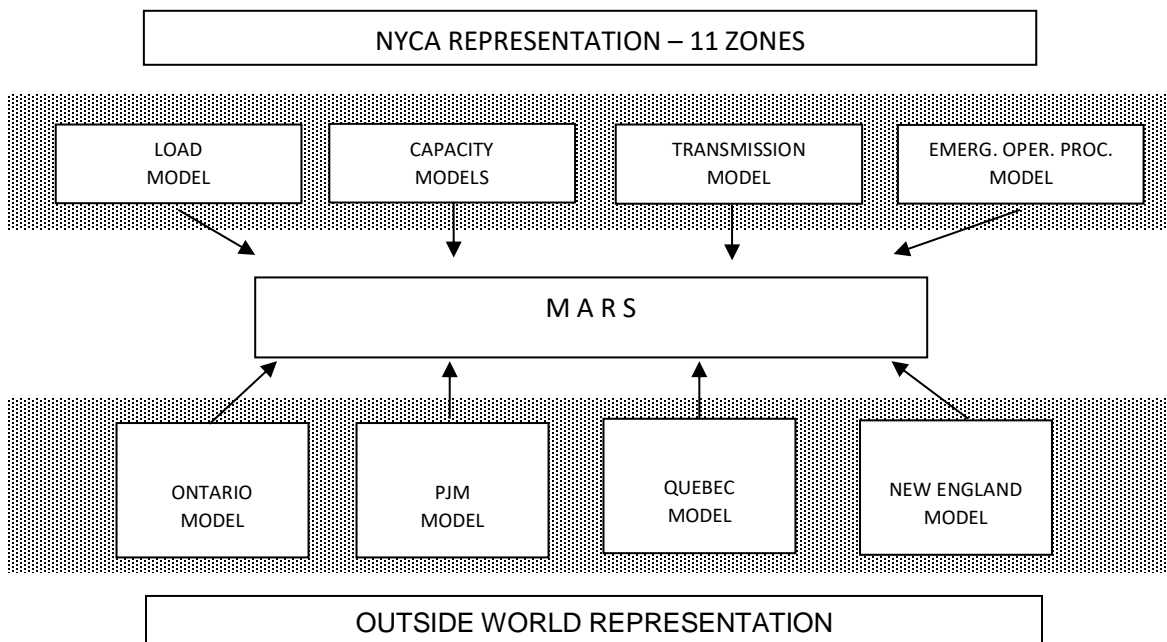
Installed Reserve Margin Study Guide

1. Reliability Calculation Models and Process

1.1 Overview of the Study Process

The purpose of this guide is to describe the process for a technical study, conducted by the New York State Reliability Council (NYSRC) Installed Capacity Subcommittee (ICS), for establishing the New York Control Area (NYCA) Installed Reserve Margin (IRM). This study is conducted annually in compliance with Section 3.03 of the NYSRC Agreement which states that the NYSRC shall establish the annual statewide Installed Capacity Requirement (ICR) for the NYCA. The ICR relates to the IRM through the following equation:

$$ICR = \left(1 + \frac{IRM\ Requirement\ (\%)}{100}\right) * Forecasted\ NYCA\ Peak\ Load$$

The reliability calculation process for determining the NYCA IRM requirement utilizes a probabilistic approach. This technique calculates the probabilities of outages of generating units, in conjunction with load and transmission models, to determine the number of days per year of expected capacity shortages. The General Electric Multi-Area Reliability Simulation (MARS) is the primary computer program used for this probabilistic analysis. The result of the calculation is termed Loss of Load Expectation (LOLE), which provides a consistent measure of resource adequacy. The relationship between MARS and the various study inputs used in the NYCA IRM calculation process is depicted below.

NYCA REPRESENTATION – 11 ZONES

LOAD MODEL	CAPACITY MODELS	TRANSMISSION MODEL	EMERG. OPER. PROC. MODEL

M A R S

ONTARIO MODEL	PJM MODEL	QUEBEC MODEL	NEW ENGLAND MODEL

OUTSIDE WORLD REPRESENTATION

A description of the study assumptions or inputs and their source are listed in the table below:

#	Parameter	Description	Source
1	GE MARS	General Electric Multi-Area Reliability Simulation Program	
2	11 Zones	Load Areas	Fig A-1
3	Zone Capacity Models	Generator models for each generating in zone Generator availability Unit ratings	GADS data Gold Book
4	Emergency Operating Procedures	Reduces load during emergency conditions to maintain operating reserves	NYISO
5	Zone Load Models	Hourly loads	NYCA load shape and peak forecasts
6	Load Uncertainty Model	Account for forecast uncertainty due to weather conditions	Historical data
7	Transmission Capacity Model	Emergency transfer limits of transmission interfaces between zones	NYISO Transmission Studies
8	Ontario, Quebec, ISONE, PJM Control Area Parameters	See items 9-12 below	Supplied by External Control Area
9	External Control Area Capacity models	Generator models in neighboring Control Areas	Supplied by External Control Area
10	External Control Area Load Models	Hourly loads	Supplied by External Control Area
11	External Control Area Load Uncertainty Models	Account for forecast uncertainty due to economic conditions	Supplied by External Control Area
12	Interconnection Capacity Models	Emergency transfer limits of transmission interfaces between control areas.	Supplied by External Control Area

The first objective in the study process is to update the study assumptions and input them into the MARS model. This is done in a stepwise process known as parametric analysis. Each assumption is input into the model and the MARS model is adjusted back to an LOLE of 0.1 days per year. The impact of the assumption update is evaluated based how much it changes the IRM relative to the prior year study IRM and

the IRM that resulted from previous step. If the impact is in the expected direction and magnitude, the assumption update is assumed to be validated. If the result is unexpected, the ICS will initiate further investigation to explain the unexpected result. If the further investigation shows that the result was not valid, the assumption is updated. This process continues until all the input assumptions have been updated and validated.

With the data base complete the next step is to prepare the preliminary base case and start the sensitivity analysis. Sensitivity studies are run to determine IRM outcomes using different assumptions than in the base case. Sensitivity studies provide a mechanism for illustrating "cause and effect" of how some performance and/or operating parameters and study assumptions can impact reliability and the IRM.
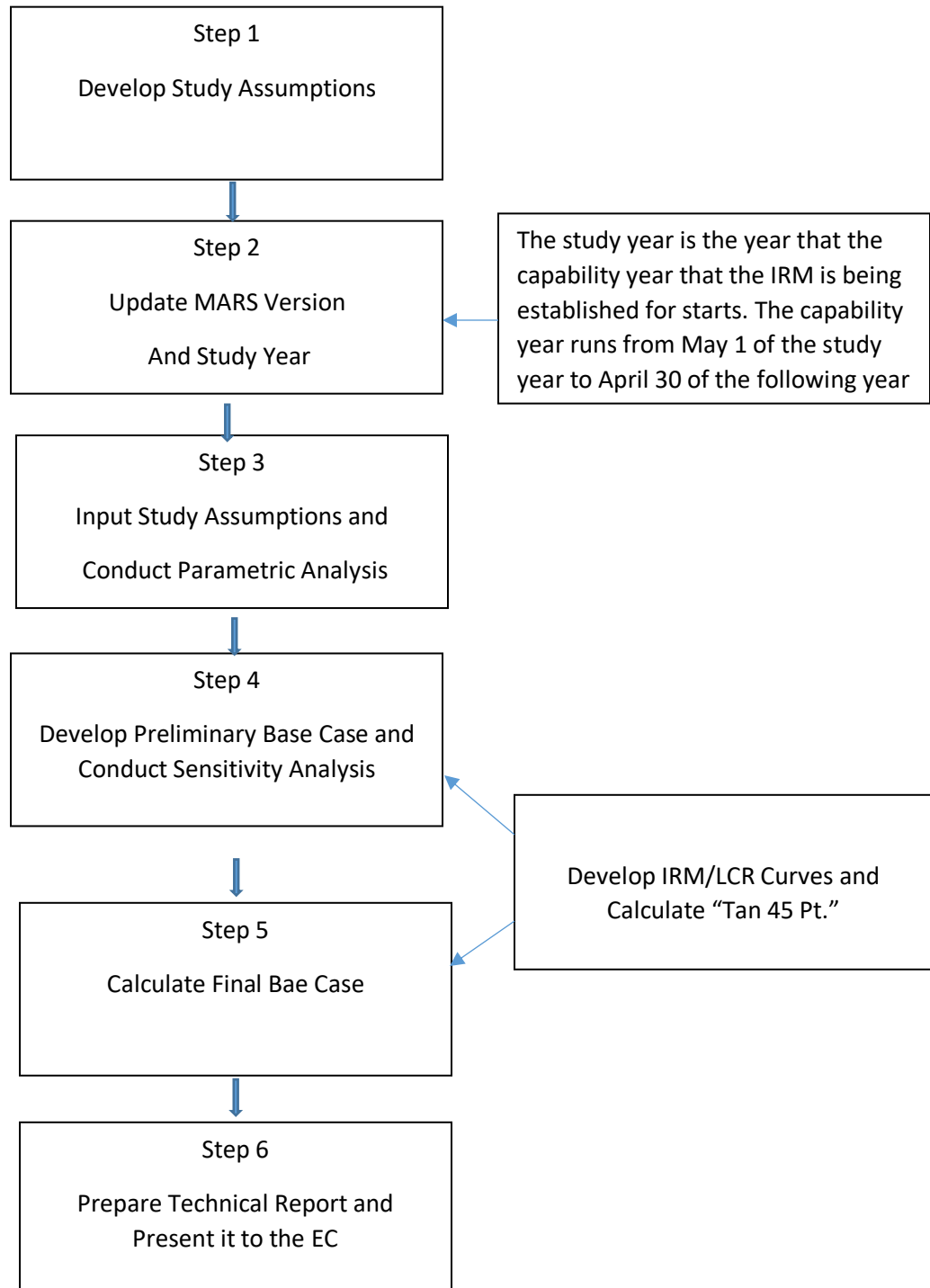
A key element in developing the base case is to construct the IRM/Locational Capacity Requirement (LCR) curves. In the NY IRM study key transmission interfaces between the eleven load zones are modeled. The interfaces between Long Island locality or Zone K and the New York City locality or Zone J are referred to the cable interfaces because these localities are supplied by high voltage underground and underwater cables which also have their own outage rates. These localities have a minimum amount capacity that needs to be located there in order to maintain 0.1 days per year LOLE. In general, the more capacity installed in the locality above the minimum the lower the statewide reserve requirement. This is because having more capacity in the locality reduces risk of not being able to deliver energy to the load in the locality. The implicit impact of this deliverability risk is to make capacity upstream of the transmission interfaces look less available to the load in the localities as opposed to the capacity being located in the locality. The IRM is inversely proportional to the availability of the capacity.

The IRM/LCR curves are the basis for the IRM base case both the preliminary and final. One curve is developed for Zone J and one for Zone K. This process is described in more detail later in the guide. The objective is to determine what is defined as the "tan 45 point". This is the point at which the slope of the curves is calculated to be zero. This point determines the study base case result for the IRM and LCR pairs. This method was developed early 2000's as a process for selecting a specific IRM/LCR pairs that were repeatable and consistent from year to year. The Upstate Downstate study conducted at the request of the Federal Energy Regulatory Commission (FERC) demonstrated the validity of this approach and the process was resulting in a well-balanced trade-off between generation requirements in the localities and the rest-of-state.

The final step in the IRM study process is to calculate the final base case, complete any outstanding sensitivity cases and prepare the technical report for the Executive

Committee. The next page presents a flow diagram which summaries the study process.

Flow Diagram Summarizing the IRM Study Process

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┌─────────────────────────────────┐
│            Step 1               │
│                                 │
│    Develop Study Assumptions    │
│                                 │
└─────────────────────────────────┘
              │
              ▼
┌─────────────────────────────────┐        ┌─────────────────────────────────┐
│            Step 2               │        │ The study year is the year that the │
│                                 │        │ capability year that the IRM is being │
│       Update MARS Version       │ ◄───── │ established for starts. The capability │
│                                 │        │ year runs from May 1 of the study │
│         And Study Year          │        │ year to April 30 of the following year │
└─────────────────────────────────┘        └─────────────────────────────────┘
              │
              ▼
┌─────────────────────────────────┐
│            Step 3               │
│                                 │
│    Input Study Assumptions and  │
│                                 │
│    Conduct Parametric Analysis  │
└─────────────────────────────────┘
              │
              ▼
┌─────────────────────────────────┐
│            Step 4               │
│                                 │
│  Develop Preliminary Base Case and │
│    Conduct Sensitivity Analysis │
└─────────────────────────────────┘
              │
              ▼                                    ┌─────────────────────────────────┐
┌─────────────────────────────────┐               │   Develop IRM/LCR Curves and    │
│            Step 5               │ ◄──────────────│    Calculate "Tan 45 Pt."       │
│                                 │               └─────────────────────────────────┘
│      Calculate Final Bae Case   │
└─────────────────────────────────┘
              │
              ▼
┌─────────────────────────────────┐
│            Step 6               │
│                                 │
│    Prepare Technical Report and │
│       Present it to the EC      │
└─────────────────────────────────┘
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The balance of the guide provides an in-depth description of the MARS methodology, the model inputs, and the methodology for calculating the base case IRM and the preparation of the technical report.

1.2 GE MARS

1.2.1 Methodology

As the primary probabilistic analysis tool used for establishing NYCA IRM requirements, the GE-MARS program includes a detailed load, generation, and transmission representation for 11 NYCA Zones, as well as the four external Control Areas (Outside World Areas) interconnected to the NYCA (see Section A-3 for a description of these Zones and Outside World Areas).

A sequential Monte Carlo simulation forms the basis for GE-MARS. The Monte Carlo method provides a fast, versatile, and easily expandable program that can be used to fully model many different types of generation, transmission, and demand-side options. GE-MARS calculates the standard reliability indices of daily and hourly LOLE (days/year and hours/year) and Loss of Energy Expectation (LOEE in MWh/year). The use of sequential Monte Carlo simulation allows for the calculation of time-correlated measures such as frequency (outages/year) and duration (hours/outage). The program also calculates the need for initiating Emergency Operating Procedures (EOPs), expressed in days/year (see Section A-3.5).

In addition to calculating the expected values for the reliability indices, GE-MARS also produces probability distributions that show the actual yearly variations in reliability that the NYCA could be expected to experience. In determining NYCA reliability, there are several types of randomly occurring events that must be taken into consideration. Among these are the forced outages of generating units and transmission capacity. Monte Carlo simulation models the effects of such random events. Deviations from the forecasted loads are captured by the use of a load forecast uncertainty model.

An important issue in using Monte Carlo simulation programs such as GE-MARS is the number of years of power system operations that must be simulated to achieve an acceptable level of statistical convergence in the expected value of the reliability index of interest. The degree of statistical convergence is measured by the standard

deviation of the estimate of the reliability index that is calculated from the simulation data.

The standard deviation has the same physical units (e.g., days/year) as the index being estimated, and thus its magnitude is a function of the type of index being estimated. Because the standard deviation can assume a wide range of values, the degree of convergence is often measured by the standard error, which is the standard deviation of the estimated mean expressed as a per unit of the mean.

Convergence can also be expressed in terms of a confidence interval that defines the range in which you can state, with a given level of confidence that the actual value falls within the interval. For example, a range centered on the mean of two standard deviations in each direction (plus and minus) defines a confidence interval of 95%.

Monte Carlo simulation approaches can be categorized as "non-sequential" and "sequential". A non-sequential simulation process does not move through time chronologically or sequentially, but rather considers each hour independent of every other hour. Because of this, non-sequential simulation cannot accurately model issues that involve time correlations, such as maintenance outages, and cannot be used to calculate time-related indices such as frequency and duration.

Sequential Monte Carlo simulation (used by GE-MARS) steps through the year chronologically, recognizing the status of equipment is not independent of its status in adjacent hours. Equipment forced outages are modeled by taking the equipment out of service for contiguous hours, with the length of the outage period being determined from the equipment's mean time to repair. Sequential simulation can model issues of concern that involve time correlations, and can be used to calculate indices such as frequency and duration. It also models transfer limitations between individual areas.

Because the GE-MARS Program is based on a sequential Monte Carlo simulation, it uses state transition rates, rather than state probabilities, to describe the random forced outages of the thermal units. State probabilities give the probability of a unit being in a given capacity state at any particular time, and can be used if one assumes that the unit's capacity state for a given hour is independent of its state at any other hour. Sequential Monte Carlo simulation recognizes the fact that a unit's capacity state in any given hour is dependent on a given state in previous hours and influences its state in future hours. It thus requires additional information that is contained in the transition rate data.

For each unit, a transition rate matrix is input that shows the transition rates to go from each capacity state to each other capacity state. The transition rate from state A to state B is defined as the number of transitions from A to B per unit of time in state A (Equation A-1).

$$Transition\ (A\ to\ B) = \frac{Number\ of\ Transitions\ from\ A\ to\ B}{Total\ Time\ in\ State\ A}$$

Table A-2 shows the calculation of the state transition rates from historic data for one year. The Time-in-State Data shows the amount of time that the unit spent in each of the available capacity states during the year; the unit was on planned outage for the remaining 760 hours. The Transition Data shows the number of times that the unit transitioned from each state to each other state during the year. The State Transition Rates can be calculated from this data. For example, the transition rate from state 1 to state 2 equals the number of transitions from 1 to 2 divided by the total time spent in state 1 (Equation A-2).

$$Transition\ (1\ to\ 2) = \frac{(10\ Transitions)}{5,000\ Hours}$$
$$= 0.002$$

Time in State Data				Transition Data			
State	MW	Hours		From State	To State 1	To State 2	To State 3
1	200	5000		1	0	10	5
2	100	2000		2	6	0	12
3	0	1000		3	9	8	0

State Transition Rates			
From State	To State 1	To State 2	To State 3
1	0.000	0.002	0.001
2	0.003	0.000	0.006
3	0.009	0.008	0.000

From the state transition rates for a unit, the program calculates the two important quantities that are needed to model the random forced outages on the unit: the average time that the unit resides in each capacity state, and the probability of the unit transitioning from each state to each other state.

Whenever a unit changes capacity states, two random numbers are generated. The first is used to calculate the amount of time that the unit will spend in the current state; it is assumed that the time in a state is exponentially distributed, with a mean as computed from the transition rates. This time in state is added to the current simulation time to calculate when the next random state change will occur. The second random number is combined with the state transition probabilities to determine the state to which the unit will transition when it leaves its current state. The program thus knows for every unit on the system, its current state, when it will be leaving that state, and the state to which it will go next.

Each time a unit changes state, because of random state changes, the beginning or ending of planned outages, or mid-year installations or retirements, the total capacity available in the unit's area is updated to reflect the change in the unit's available capacity. This total capacity is then used in computing the area margins each hour.

1.2.2 Development of Generator Transition Rate Matrices
Introduction

The GE MARS Program is based on a sequential Monte Carlo simulation which uses state transition rates, rather than state probabilities, to describe the random forced outages of the generating units. State probabilities give the probability of a unit being in a given capacity state at any particular time, and can be used if one assumes that the unit's capacity state for a given hour is independent of its state at any other hour. Sequential Monte Carlo simulation recognizes the fact that a unit's capacity state in a given hour is dependent on a given state in previous hours and influences its state in future hours. It thus requires additional information that is contained in the transition rate data.

The NYISO capacity market transacts in unforced capacity or UCAP. UCAP is determined by multiplying a generating resource's DMNC, or CRIS if less than DMNC, by its Equivalent Demand Forced Outage Rate (EFORd). EFORd is the industry standard index for determining generating unit performance in competitive markets. Because peaking units normally operate for relatively short periods of time, the basic two-state model was extended to a four-state representation in order to recognize this behavior. The Institute of Electrical and Electronic Engineers' (IEEE) four-state or EFORd model was developed in 1972 [1]. The EFORd is defined in the IEEE Standard 762 entitled: "IEEE Standard Definitions for Use in Reporting Electric

Generating Unit Reliability, Availability, and Productivity" [9]. The standard can be found on nerc.com at the following link:

http://www.nerc.com/docs/pc/gadstf/ieee762tf/762-2006.pdf.

Measures of generating unit performance have been defined, recorded, and utilized by the electric power industry for several decades. The North American Electric Reliability Corporation (NERC)'s Generator Availability Data System (GADS) is the process utilized in the power industry for reporting generator performance data. Generating resources subject to mandatory reliability standards are required to report GADS data as described in NERC's "Data Reporting Instructions" [2]. The reporting instructions can be found at the following link:

http://www.nerc.com/pa/RAPA/gads/Pages/Data%20Reporting%20Instructions.aspx.

It is important that there be consistency between the EFORd calculations utilized in the NYISO capacity markets and MARS transition rate matrices. In order for the MARS LOLE simulation to be consistent with the EFORd calculations, the transition rate matrix needs to maintain the conditional state probabilities used in the EFORd calculation. Two approaches were developed by Dr. Chanan Singh of Associated Power Analysts (APA) and provided in APA's report [3], which provides the basis for the methodology described in Appendix E. Approach 1 with some modification was the one that was selected for implementation with the GADS Open Source software.

Assumptions for the Methodology

The purpose of the methodology is to develop transition rates that yield EFORds of the units which are consistent with the formulae used by NYISO's capacity markets. The main difficulty in this process lies in the fact that programs like MARS assume that the units are running all the time and there are no mechanisms in these programs to start the units during the period of need and put them on reserve shutdown when not needed. However, EFORd is computed based on the derated and forced outage states given the period of demand.

The following points are working assumptions that underlie the development of the MARS transition rate methodology:

- Embedded in the EFORd calculation are the following three steps:

  a. Finding times spent in various states during demand;

  b. Converting these times into conditional probabilities;

  c. Adjusting the times in derated states to equivalent times in the full forced outage state.

- Under the present state of data collection, the accepted practice is to assume that the conditional probabilities calculated for EFORd procedure are the benchmark.

- For the MARS calculations of LOLE to be consistent with the EFORd calculations, the transition rate matrix should maintain the conditional state probabilities used in the EFORd calculation.

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- MARS does not have mechanisms for starting units in response to demand or shutting down when not needed [4, 5]. Therefore, the program essentially assumes the units are running, in service, or in demand all the time.

- To be consistent with the assumption of the units running all the time, models conditional on the demand should to be used.

- The EFORd calculation formula is based on the conditional probabilities of the states and these conditional probabilities should be assumed as a good estimate of the performance. So, the transition rate matrix should be constructed to maintain these conditional probabilities. The conditional approach used in the four-state model [1] that forms the basis of EFORd calculations was in fact proposed to deal with the assumption of units running all the time.

Development of the Methodology

For ease of discussion, the methodology will be described using a unit with two derated states [10], which will later be extended to any number of derated states. The model in Figure E-1 is a representation of the state space of this unit with two derated capacity levels and one full outage level. The states during the reserve shutdown and demand are shown separately at all capacity levels. The service hours SH are then the hours spent in states 5, 6 and 7.

The hours spent in state i are denoted by H_i. Assume that the total time in a derated capacity state is known, but its components during demand and reserve shutdown are not known separately. For example, the sum $(H_6 + H_2)$ may be known, but not H_2 and H_6 individually. Consistent with the approach used for the EFORd calculation, the hours in the various derated states and down state during demand can be estimated as:
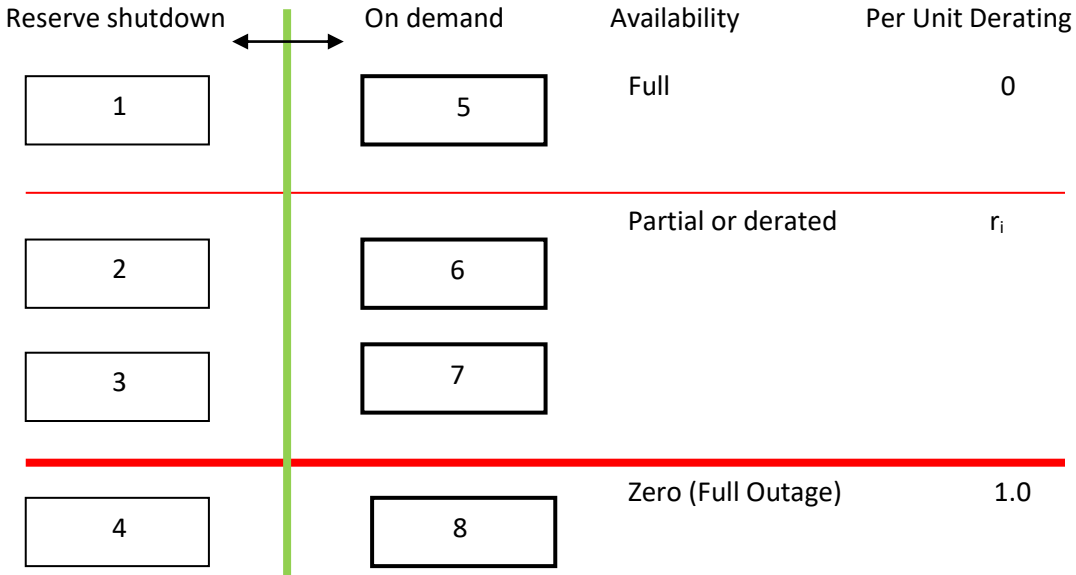
$$H_6 = (H_6 + H_2) f_p \ (1)$$

$$H_7 = (H_7 + H_3) f_p \ (2)$$

$$H_8 = (H_8 + H_4) f_f \ (3)$$

Knowing the components of derated times during demand,

$$H_5 = SH - H_6 - H_7 \,(4)$$

The f factors used in these equations are defined in Appendix F of NERC's "Data Reporting Instructions" [2] along with the equations for their calculations. Of course, if the data kept allows the knowledge of H_6, H_7, and/or H_8 individually, then there is no need to use the f factors. From a conceptual perspective it can be stated that it should be possible to keep such data for derated states as they are similar to the full capacity state except with reduced capacity. However, for the forced outage state it may be hard to assign when the transition to reserve shut down happens. This is because when the unit is forced out, one can only calculate when the duty cycle would have ended.

Reserve shutdown		On demand	Availability	Per Unit Derating
1		5	Full	0
2		6	Partial or derated	r_i
3		7		
4		8	Zero (Full Outage)	1.0

Figure E-1. States of a unit with two derated capacity levels

The conditional probabilities of states, 5 to 8, given demand can be estimated as

$$P5d = H5 / Sum \quad (5)$$

$$P6d = H6 / Sum \quad (6)$$

$$P7d = H7 / Sum \quad (7)$$

$$P8d = H8 / Sum \quad (8)$$

Where Sum = $H_5 + H_6 + H_7 + H_8$

The additional subscript d is used to indicate that these are probabilities given demand.

The EFORd can be calculated from these probabilities as

$$EFORd = r_1 P_{6d} + r_2 P_{7d} + P_{8d} \quad (9)$$

It is reasonable to assume that in the absence of the programs to start and shut down units, the use of conditional probabilities given demand (equations (5)-(8)) for the states of the system is the appropriate approach. However, MARS uses transition rates to generate the history of the states of the units and it does not have a mechanism to start and shut down units. Therefore, transition rates are needed such that the conditional probabilities of states remain the same as given by equations (5)-(8).

If there are n states of the new unit, then the maximum number of frequency balance equations [6, 7, 11] is n-1 but the number of possible transition rates is n(n-1). It should be noted that the probability based indices like LOLE and EUE may not be affected by the choice of the solution for transition rates, but any frequency based index will be affected by the choice of transition rates.

Let's define an (n x n) matrix N such that its ijth element N_{ij} is the number of times the unit changes from state i to state j, then the transition rate from i to j is given by

$$\lambda_{ij} = N_{ij} / H_i \qquad (10)$$

Where H_i is the time spent in state i.

Now the matrix N needs to satisfy the following property:

$$\sum_{j, j \neq i} N_{ij} = \sum_{i, i \neq i} N_{ij} \qquad (11)$$

This equation ensures that the frequency of entering a state is the same as the frequency of exiting from the state [6-8]. Since in practice, the data may not be collected over a long enough time, equation (11) may only be approximately satisfied for every state. It should be noted that the column sum of N is the frequency of entering the state and the row sum is the frequency of exiting the state. So to ensure the frequency balance, the column sum for every state should be equal to its row sum.

MARS Transition Rate Methodology

The approach of the methodology can be generalized as follows. It is assumed that SH=Hours in the full capacity operating state + Derated Hours during the demand period.

- Let there be n capacity states of the unit, state 1 with capacity of 1 pu, state n with 0 pu and states 2 to n-1 as derated states.

- Determine the matrix N representing number of interstate transitions and it should satisfy the property given by equation (11) very closely.

- The time in state 1 is given by

$$H_1 = \text{SH - Total Derated Hours x } f_p$$

The time in the full outage state n is

$$H_n = \text{FOH x } f_f$$

The times in derated states 2 to n-1 are given by

$$H_i = (\text{Hours in derated state i}) \text{ x } f_p$$

In these calculations, it is assumed that the times spent in a combined derated state (Reserve and Demand) are not individually known but their total (Reserve + Demand) is known. So, the individual times are found using the f_p factor just like in the EFORd calculation. If the times in the two components of a derated state (Reserve or Demand) are individually known, then they can be used instead of apportioning the times from the combined state by the f_p factor. **It should be noted that the times in the derated states can be individually known from the GADS data collected by the NYISO, which eliminates the need for the f_p factor in the NYISO implementation.**

- Find the transition rates using

$$\lambda_{ij} = N_{ij} / H_i$$

The probabilities of states can be determined from the transition rate matrix and the EFORd can be calculated as

$$\text{EFORd} = P_n + \sum_{i=2}^{n-1} r_i P_i \qquad (12)$$

Implementation and Validation of the MARS Transition Rate Methodology

In order to generate the metrics needed to populate the transition rate matrices for the generating units modeled in MARS, the above methodology was coded into the GADS Open Source software package but modified as described above. The GADS Open Source (GADS OS) is the software utilized by the NYISO to analyze generator performance data. It is used to calculate the generator performance indexes used in determining a generator's UCAP value and, now, for developing the transition rates that are used in the MARS model. GADS OS allows electric generating companies to collect and report validated GADS performance data and event data. GADS OS can be found at this link:

http://gadsopensource.com/

GADS OS, written by industry veteran Ron Fluegge, consists of two open source applications—GADS OS Data Entry and GADS OS Analysis & Reporting to analyze the GADS data. Besides the use of this software for submittal of GADS data to NERC and the NYISO, the software is also used for submittal of data to the ISO New England, PJM, and the MISO.

Measures of generating unit performance—such as Availability Factor (AF), Equivalent Availability Factor (EAF), Forced Outage Rate (FOR), Equivalent Forced Outage Rate (EFOR), and Starting Reliability—have been defined, recorded, and utilized by the electric power industry for several decades. Analysis & Reporting not only calculates these important standard measures, but also includes measures such as the Equivalent Demand Forced Outage Rate (EFORd) used in UCAP/ICAP calculations that have been developed to respond to the deregulated capacity and energy markets.

GADS OS is already in use at a wide range of generating companies from single-plant sites to larger generating companies with hundreds of generating units. The latest count shows that the GADS OS code base is being used to collect and analyze data on more than 200 companies and 3,800 generating units both domestically and internationally.

In order to correctly calculate the transition rates of a unit using its historic events-data, its state durations need to be in a strictly seamless sequence without any overlapping. There will be little difficulty in calculations if the raw data events are in an ideal sequence, i.e., the beginning time of any event is equal to or later than the ending time of its previous event. However, it was found that in the raw data there are quite a few records indicating existence of overlapping events. In addition, some records even show discrepancies in the sequence of events, e.g., an event started and ended before the beginning time of its previous event. All

these discrepancies in raw data will frustrate the standard programming algorithms and can cause erroneous calculation results.

As a result, two pretreatment procedures were developed before the raw events data can be used for calculating transition rates. When events in mistaken sequence are found, their places in the overall event sequence list will be reordered by the Pretreatment Procedure 1—Handling Mistaken Sequence of Events. Unless all mistaken sequence records of a unit are corrected, the next Pretreatment Procedure 2—Handling Overlapping Events should not begin.

In order to benchmark statistics in the performance data, Pretreatment Procedure 2 is based on the following classification of event priority levels.

Priority Level	Event Types	Event Code in GADS
1st	Forced Outage, Startup Failure	U1, U2, U3, SF
2nd	Reserve Shutdown	RS
3rd	Planned Outage and its Extension, Maintenance Outage and its Extension	PO, PE, MO, ME
4th	Forced Derating (lower net available capacity)	D1, D2, D3
5th	Forced Derating (higher net available capacity)	D1, D2, D3
6th	Planned Derating and its Extension, Maintenance Derating and its Extension	PD, DP, D4, DM
7th	Non-curtailing Event	NC
8th	Full capacity (gaps between adjacent events)	--

The different types of events in the same priority level are observed not to be overlapping data records. For any two adjacent overlapping events from different priority levels, four rules for appropriate handling are summarized as follows.

(1) If the lower priority event started before the beginning time of the higher priority event, and the lower priority event ended before or at the same time as the ending time of the higher priority event, adjust the ending time of the lower priority event benchmarking the beginning time of the higher priority event.

(2) If the lower priority event started before the beginning time of the higher priority event, and the lower priority event ended after the ending time of the higher priority event, replace the original lower priority event by two new separate events. For the first new event, inherit the beginning time of the original lower priority event as its beginning time, and adopt the

beginning time of the higher priority event as its ending time. For the second new event, inherit the ending time of the original lower priority event as its ending time, and adopt the ending time of the higher priority event as its beginning time.

(3) If the lower priority event started at the same time as or after the beginning time of the higher priority event, and the lower priority event ended before or at the same time as the ending time of the higher priority event, invalidate the lower priority event for transition rate calculation.

(4) If the lower priority event started at the same time as or after the beginning time of the higher priority event, and the lower priority event ended after the ending time of the higher priority event, adjust the beginning time of the lower priority event benchmarking the ending time of the higher priority event.

After Pretreatment Procedure 2, an additional rule is also applied to eliminate possible human errors for raw data gaps. This is the Rule of Seamlessness: If the time gap between any two adjacent events is no greater than 1 minute, it will be ignored and the two events are considered as neighboring events. Otherwise, the time gap will be regarded as an event of full-capacity state existing between the two adjacent events.

It is important to note that all the derating states remaining in the sequential event list after above raw data pretreatment procedures are already separated from reserve shutdown states. Hence, these remaining derating states are actually in demand. When counting the total durations of these derating states for calculating transition rates, the f_p factor is no longer necessary. However, the f_f factor is still needed since there is no good way to distinguish in-demand or not-in-demand states when a unit is actually in a forced outage status.

The use of the APA methodology as coded in the GADS OS software with data pretreatment resulted in small differences (less than 0.6% of the total NYCA resources or approximately 225 MW) between the Market calculated EFORds and the GADS OS generated EFORds as implemented in GADS OS [12]. Most of these differences are accounted for in the data used for the calculation (event data versus performance data) and the differing formulae themselves (fp in the market calculation versus direct determination of EFDHs in computing transition rates). The small difference between the total UCAP determined by the NYISO Market EFORd formula and the GADS OS transition rate calculation demonstrates that the methodology for populating generator transition rate matrices for MARS that are consistent with the EFORd reliability index has been successfully implemented.

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1.3. Unified Methodology

1.3.1 Description

Introduction

Below is described the procedure utilized to develop the statewide Installed Reserve Margin (IRM) versus Minimum Locational Capacity Requirements (LCRs) curves.

Within the New York Control Area (NYCA) there are currently two zones for the purpose of the IRM study that are identified as localities to which this procedure would apply. They are the New York City and Long Island zones.

Initial Conditions

- A Multi-Area Reliability Simulation (MARS) base case database exists for the upcoming capability year.
- Localities in the NYCA that require minimum LCR have been identified (in Section 1).
- Any capacities that have been shifted, removed, or added to arrive at the base case for the IRM study should be reset to the "as found" case before initiating this procedure. This procedure should start with the forecast capacities, and forecast loads.

Setting up the base case model for a desired study reserve margin (SRM)

Installed capacity (ICAP) is either added to or removed from zones west of the Total East Interface that have excess capacity reserves (capacity rich zones) so that the statewide capacity to peak load ratio equals the desired study reserve margin (SRM) point.

- A portion of this installed capacity (ICAP) is added to or removed from each capacity rich zone. The amount to be added to or removed from each capacity rich zone is based on the ratio of its excess unforced capacity (UCAP) to the total excess unforced capacity (UCAP) of all capacity rich zones.
- Capacity removal or addition is achieved by adjusting the respective entry for each capacity rich zone in the MOD-MDMW table of the MARS program. The amount entered in the table is the equivalent UCAP amount for the amount of ICAP to be removed or added. UCAP for a zone is equal to the ICAP for that zone times one minus the weighted equivalent forced outage rate (1-EFOR) for the zone.
- The correct amount of ICAP added to or removed from NYCA should be verified by performing a single iteration MARS run using the capacity adjusted model, checking the total capacity from the MARS 07 output file, and calculating the achieved reserve margin.
- Run the MARS model for 1,000 iterations. If at the 1000th iteration the desired standard error of 0.025 of the mean LOLE for calculating the 95% confidence level is not achieved, the NYISO will notify the ICS and then increase the number of iterations in increments 250 until the desired standard error is met or exceeded.

Determination of the initial target capacity for each locality

The initial target capacity for a locality is the maximum capacity that is shifted from or to the locality to yield a NYCA LOLE risk of 0.1 days/year, while all other zones and localities remain unchanged.

- Using the capacity adjusted base case from Section 3 as the base model, if the LOLE for the base case is less or greater than 0.1 days/year, remove or add respectively a trial amount of ICAP from or to the locality being considered.
- The equivalent UCAP amount to be added to or removed from the locality is entered in the respective entry for the locality in the MOD-MDMW table of the MARS program.
- To maintain the same desired reserve margin, the same ICAP amount should be removed from or added to the capacity rich zones using the steps in Section 3.0.
- Run a MARS simulation until the standard error of the LOLE index is less than or equal to 0.025 or when the maximum number of replications has been reached.
- If the NYCA LOLE is below or above 0.1 days/year, repeat Sections 4.1 to 4.4 with a higher or lower trial amount of ICAP until the NYCA LOLE reaches 0.1 days/year or within an acceptable range.
- Record the total amount of ICAP added to or removed from the locality being considered. This is the initial target capacity for the locality.
- If a NYCA LOLE of 0.1 days/year cannot be achieved, either by shifting capacity to or from the locality, the desired SRM is not achievable and a new SRM should be selected and repeat steps in Section 3.
- If a NYCA LOLE of 0.1 days/year is achieved for the locality, repeat the steps in Sections 4.1 to 4.7 for each identified locality and record the amount of ICAP capacity shift for each of these localities. These are the initial target capacities for the zones. (Before considering a new locality, reset the model to the original capacity adjusted base case, i.e. with the desired reserve margin, as described in Section 3.0)

Determination of the capacity multiplier for each locality

The capacity multiplier for an identified locality is the initial target capacity for the locality, obtained in Section 4, divided by the sum of the initial target capacities for all the identified localities. These multipliers determine the portion of the total installed capacities to be shifted for each identified locality. For example, if zones 1 and 2 are the only two localities identified, and the initial target capacities for zones 1 and 2 are 300 MW and 100 MW respectively, then the capacity multiplier for zone 1 would be 300/400 or 0.75, while the capacity multiplier for zone 2 would be 100/400 or 0.25.

Determination of the actual capacity removal or addition for each locality

- Based on the initial LOLE risk for the capacity adjusted based model obtained in Section 3, estimate a total trial amount of ICAP to be shifted from or to the identified localities.

- This trial amount of capacity will be shifted from or to the identified localities using the capacity multipliers obtained in Section 5.0. For example, using the example in Section 5.0, if 1000 MW is to be removed from zones 1 and 2, then the amount of ICAP to be removed from zone 1 would be 1000 * 0.75 or 750 MW, and for zone 2, 250 MW respectively.
- The equivalent amount of UCAP for each identified locality is then entered into the respective entries in the MOD-MDMW table of the MARS program.
- To maintain the desired SRM, the same amount of ICAP capacity must be shifted to or from the capacity rich zones. The amount of equivalent UCAP entries for each of the capacity rich zones in the MOD-MDMW table can be determined using the same steps described in Section 3.
- Run a MARS simulation until the standard error of the LOLE index is less than or equal to 0.025 or when the maximum number of replications has been reached. Record the NYCA LOLE risk.
- If the NYCA LOLE risk is below or above 0.1 days/year, increase or decrease the trial amount of ICAP to be shifted from or to the identified localities. Repeat Sections 6.2 to 6.5 until the NYCA LOLE reaches 0.1 days/year or within an acceptable range.
- Record the amount of ICAP shifted from or to each identified locality. The remaining amount of ICAP in each identified locality is the total generation in the locality, minus or plus the amount shifted for that locality.

Determination of the locational capacity requirement (LCR) for each identified locality

The locational capacity requirement (LCR) for the desired SRM for each identified locality is the ratio, expressed as a percentage, of the remaining amount of ICAP in each identified locality, obtained in Section 6.7, to the forecast peak load of the locality.

Determination of the LCR-IRM curves

Repeat Sections 3.0 to 7.0 to provide the resulting LCRs for a range of desired reserve margins. The results will be used to plot the LCR-IRM curves and determine the desired NYCA LCR-IRM as described below.

1.3.2. Selection of Tan 45 Points on IRM/LCR Curves Established by the Unified Methodology

The IRM Anchoring Method identifies the NYCA IRM Requirements and related MLCR from IRM/LCR curves established by the Unified Methodology. The *anchor point* on the curve is selected by applying a tangent of 45 degrees ("Tan 45") analysis at the bend (or "knee") of the curve as shown on Figure B-1 below. Based on these curves, extreme points on the curve on either side of the Tan 45 point may create disproportionate changes in LCR and IRM, since small changes in LCR can introduce larger changes in IRM Requirements and vice versa. A regression analysis is utilized to best fit the IRM/LCR curves and determine the Tan 45 point, rather than a visual inspection of the curves.
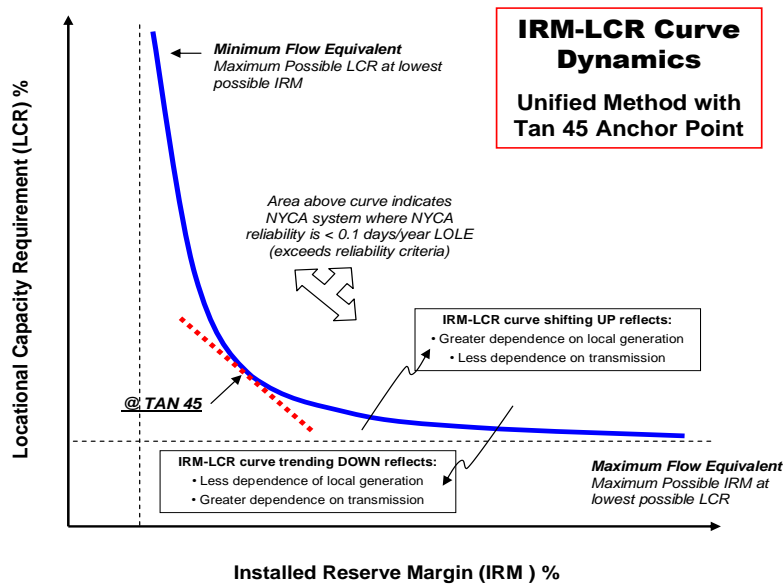
IRM-LCR Unified Method Curve Dynamics with Tan 45 Anchor Point

The IRM/LCR characteristic consists of a curve function, "a knee of the curve" and straight line segments at the asymptotes. The curve function is represented by a quadratic (second order) curve which is the basis for the Tan 45 inflection point calculation. Inclusion of IRM/LCR point pairs remote to the "knee of the curve" may impact the calculation of the quadratic curve function used for the Tan 45 calculation.

The procedure for determining the best fit curve function used for the calculation of the Tan 45 inflection point to define the base case requirement is based on the following methodology:

- Start with all points on IRM/LCR Characteristic.

- Develop regression curve equations for all different point to point segments consisting of at least four consecutive points.

- Rank all the regression curve equations based on the following:

  – Sort regression equations with highest R^2.

  – Ensure calculated IRM is within the selected point pair range, i.e., if the curve fit was developed between 14% and 18% and the calculated IRM is 13.9%, the calculation is invalid.

- In addition, there must be at least one statewide reserve margin point to the left and right of the calculated tan 45 point

- Ensure the calculated IRM and corresponding LCR do not violate the 0.1 LOLE criteria.

- Check results to ensure they are consistent with visual inspection methodology used in past years studies.

This approach identifies the quadratic curve functions with highest R^2 correlations as the basis for the Tan 45 calculation. The final IRM is obtained by averaging the Tan 45 IRM points of the NYC and LI curves. The Tan 45 points are determined by solving for the first derivatives of each of the "best fit" quadratic functions as a slope of -1. Lastly, the resulting MLCR values are identified.