NEW YORK STATE
NYSRC
RELIABILITY COUNCIL

ISO
NEW YORK
INDEPENDENT
SYSTEM OPERATOR

WORKSHOP
Establishing New York Control Area Installed Capacity Requirements

Presented by the
New York State Reliability Council

July 11, 2003
9:00 AM – 3:00 PM

NYISO Offices, 290 Washington Avenue Extension, Albany, NY
Dial-in #304-345-7506 – Participant Code: 769395

Agenda

1	Welcome-Workshop Objectives & Agenda Overview	9:00-9:10 AM	Curt Dahl
2	Probability Basics & Loss of Load Expectation Method	9:10-9:30 AM	Glenn Haringa
3	MARS: The Primary Reliability Calculation Tool	9:30-10:30 AM	Glenn Haringa
4	BREAK	10:30 – 10:45 AM	
5	NYSRC Criterion for Establishing the NYCA Installed Reserve Margin (IRM) Requirement	10:45 – 11:05 AM	Alan Adamson
6	Study Process: Multi-Area Model Representation and Development of the Base Case & Sensitivity Cases	11:05 AM – 12:00 PM	Greg Drake
	LUNCH BREAK (12:00 PM – 1:00 PM)		
7	Major Modeling Assumptions: Their Source & IRM Requirement Impacts	1:00 – 2:00 PM	Frank Vitale/ Bill Lamanna
8	Study Schedule	2:00 – 2:10 PM	Curt Dahl
9	Questions and Answers	2:10 - 3:00 PM	Curt Dahl

Workshop Objectives

- **Promote understanding of principals, methodologies, assumptions in IRM Study**
- **Increase technical knowledge of New York State Reliability Council's Installed Capacity Study and Executive Committee regarding Multi-Area Reliability Simulation and Loss of Load Expectation**
- **Provide Open Forum for Market Participants to ask questions**
- **Introduction to NYSRC Policy 5.0 *"Procedure for Establishing NYCA Capacity Requirements"***

Probability Basics and Loss-of-Load Expectation Methods

New York State Reliability Council

July 11, 2003

Glenn Haringa

GE-PSEC

Probability

- **A number expressing the likelihood that a given event will occur**

$$\text{Probability} = \frac{\text{Number of “successful” outcomes}}{\text{Number of possible outcomes}}$$

- **Value ranges from 0 to 1**
- **Examples**
  - ***Toss a balanced coin*** ***Prob. of heads*** ***1 / 2***
  - ***Toss a coin twice*** ***Prob. of 1 or more heads*** ***3 / 4***
  - ***Roll a balanced die*** ***Prob. of 1 or 5*** ***2 / 6***

Expected Value

- **The average value for a random variable**

  Expected Value = Σ x * Prob(x)

- **Value range depends on event being considered**
  - ***Not necessarily one of the possible outcomes***
- **Example**
  - ***Toss 2 coins 20 times***
  - ***x = number of heads each toss (0, 1, or 2)***
  - ***Results: 0 – 5 times; 1 – 9 times; 2 – 6 times***
  - ***Expected Value (x) = 0 * (5/20) + 1 * (9/20) + 2 * (6/20)***

    = 1.05 heads

Expected Value

Another Example

- **x = number of days per year that the high temperature exceeds 80° F**
- **Value could range from 0 to 365**
- **Review historical weather data**
  - ***Year 1 45 days***
  - ***Year 2 35 days***
  - ***Year 3 60 days***
  - ***Year 4 50 days***
  - ***Year 5 55 days***
- **Expected Value (x) = 49 days per year**

Daily Loss-of-Load Expectation

- **The expected number of days per period that the system does not have sufficient generating capacity to meet the load at time of daily peak**
  - ***Measure of generation system reliability***
  - ***Considers generating unit unavailability***
- **Could review historical data and try to predict future reliability from it**
  - ***Conditions on the generation system changing too rapidly for this approach to be accurate***
- **Calculate for future time period based on assumptions for individual system parameters**

Calculating LOLE – Analytical Method

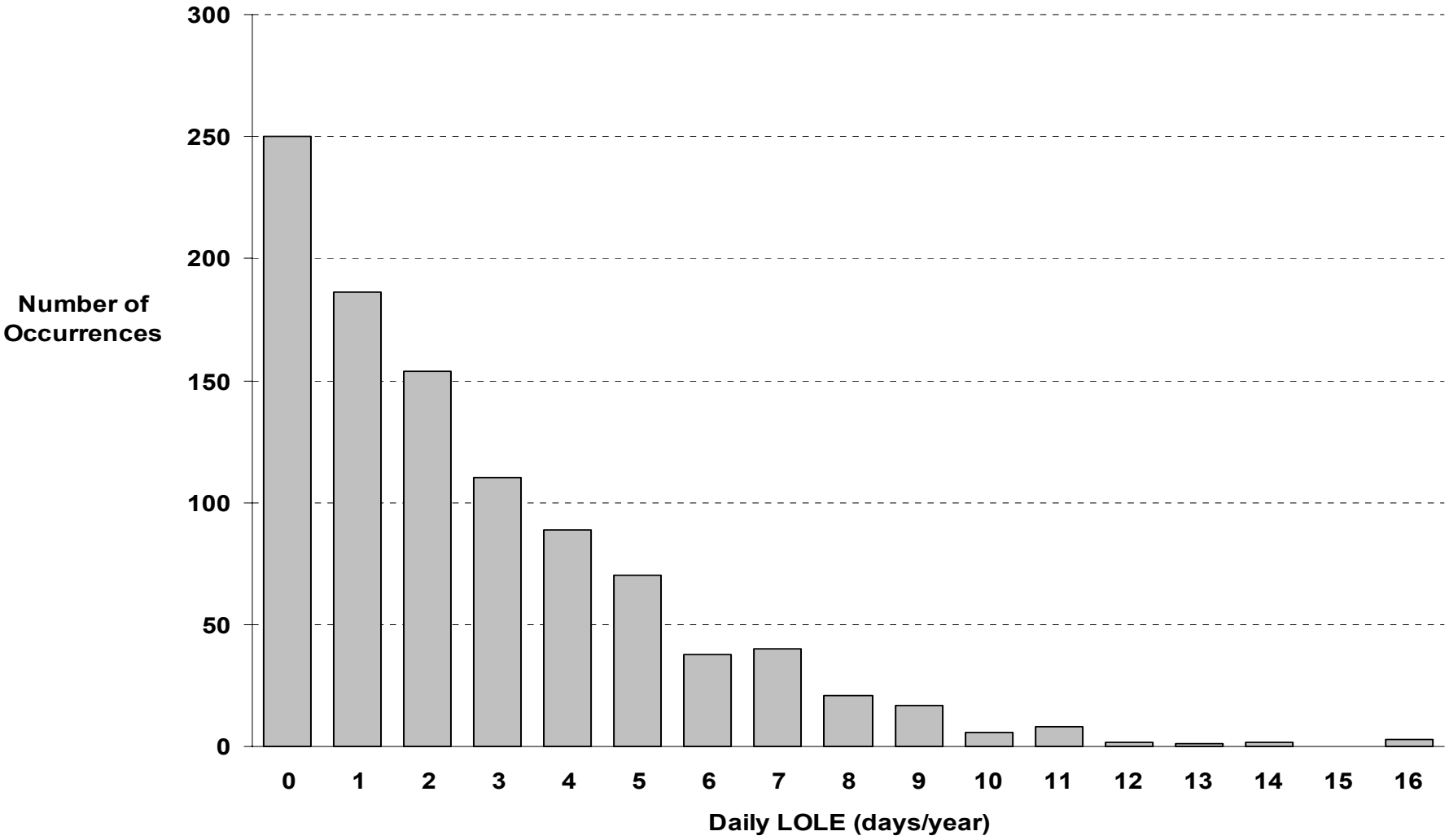
- **From unit ratings and forced outage rates, construct a capacity outage table which shows the probability of having X MW or more on outage**
  - ***Enumerates all possible outage combinations with the corresponding MW on outage and probability of occurrence***
  - ***Table changes as units are installed, retired, or are taken out for scheduled maintenance***
- **From the capacity outage table, determine the probability each day of not having sufficient capacity to meet the daily peak load**
- **Sum the daily probabilities over the year to compute the expected number of days per year**

Calculating LOLE - Monte Carlo Simulation Method

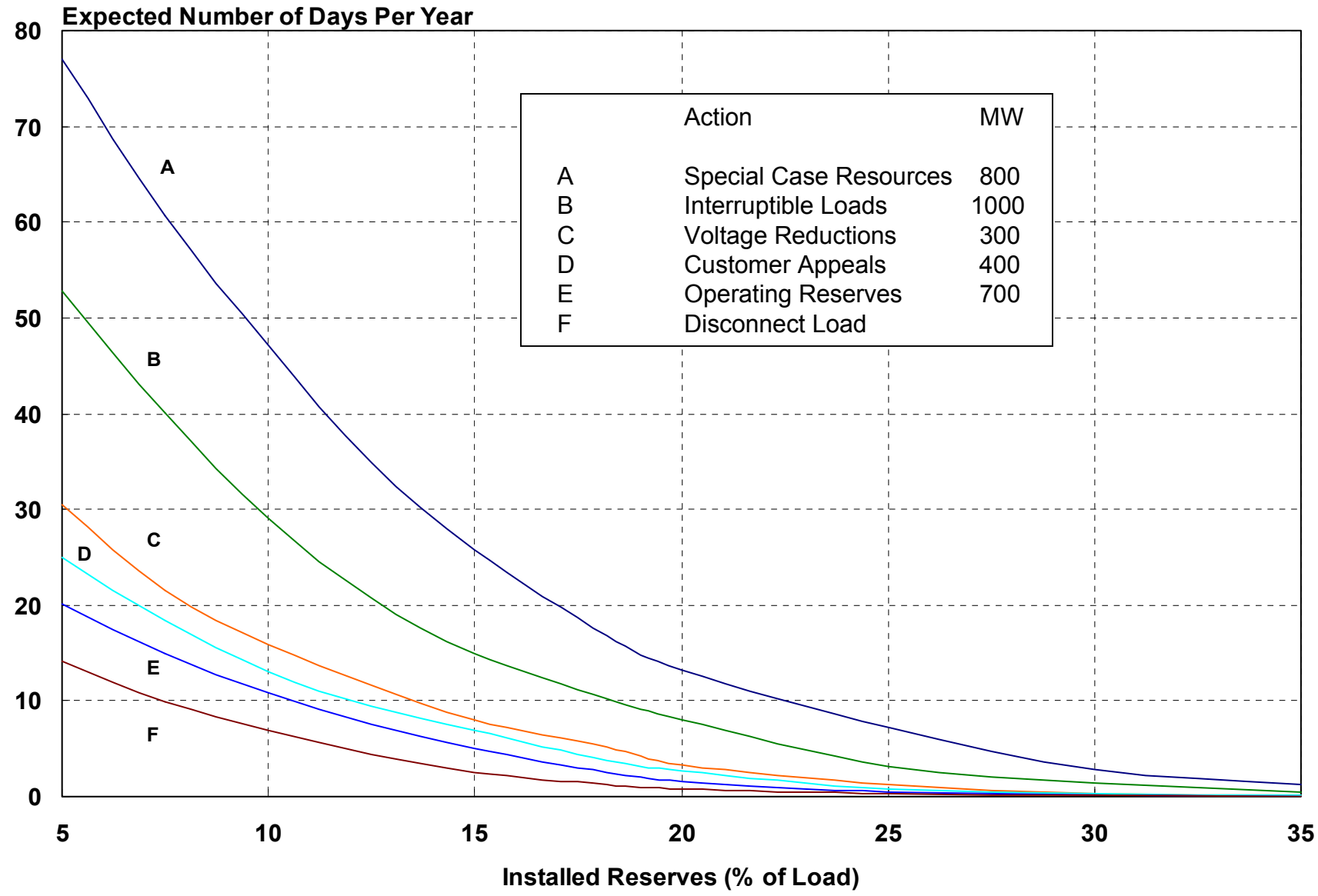
- **"Roll the dice" to determine capacity available from each unit on the system based on unit's rating and forced outage rate**
- **Sum available capacity**
- **Count number of days per year that available capacity is less than daily peak load**
  - ***Gives daily LOLE for one set of random outages***
- **Simulate the year with additional sets of random outages**
  - ***Each simulation is also referred to as a "replication"***
- **Expected value is the average of the results for the individual replications**

Results from Monte Carlo Simulation

Expected Value = 2.6 Days/Year



Expected Need for EOPs



Emergency Operating Procedures

Example

Operating Reserve Requirement = 1200 MW

EOP Procedure	MW Benefit
Special Case Resources	800
Interruptible Loads	1000
Voltage Reductions	300
Customer Appeals	400
Reduce Operating Reserves	700

Margin State	MW
1	1200
2	400
3	-600
4	-900
5	-1300
6	-2000

Emergency Operating Procedures

- **Staggered Implementation of EOPs**
  - ***Deficient zone must implement specified number of EOPs before other zones begin***
  - ***Input separately for***
    - *zones within same Area*
    - *zones in outside Areas*
- **Isolated**
  - ***EOPs used by each zone as needed to meet load after dispatch of EL2 units***
- **Interconnected**
  - ***EOPs used as last resort after***
    - *dispatch of EL2 units*
    - *assistance from other zones*
    - *contract curtailments*

Emergency Operating Procedures

- **Impact of EOPs modeled by evaluating daily LOLE at specified positive and negative margin states**
- **Up to 10 margin states available for each zone**
- **Specify margin states as**
  - ***Cumulative EOP benefit (MW), or***
  - ***Actual EOP benefit as sum of***
    - *fixed MW*
    - *per unit of zone load*
    - *per unit of available zone capacity*
- **Limit on number of days implemented each month**
- **Specify whether EOP benefits**
  - ***Zone only***
  - ***Other zones within same Area***
  - ***All zones in system***

Resource Allocation Process

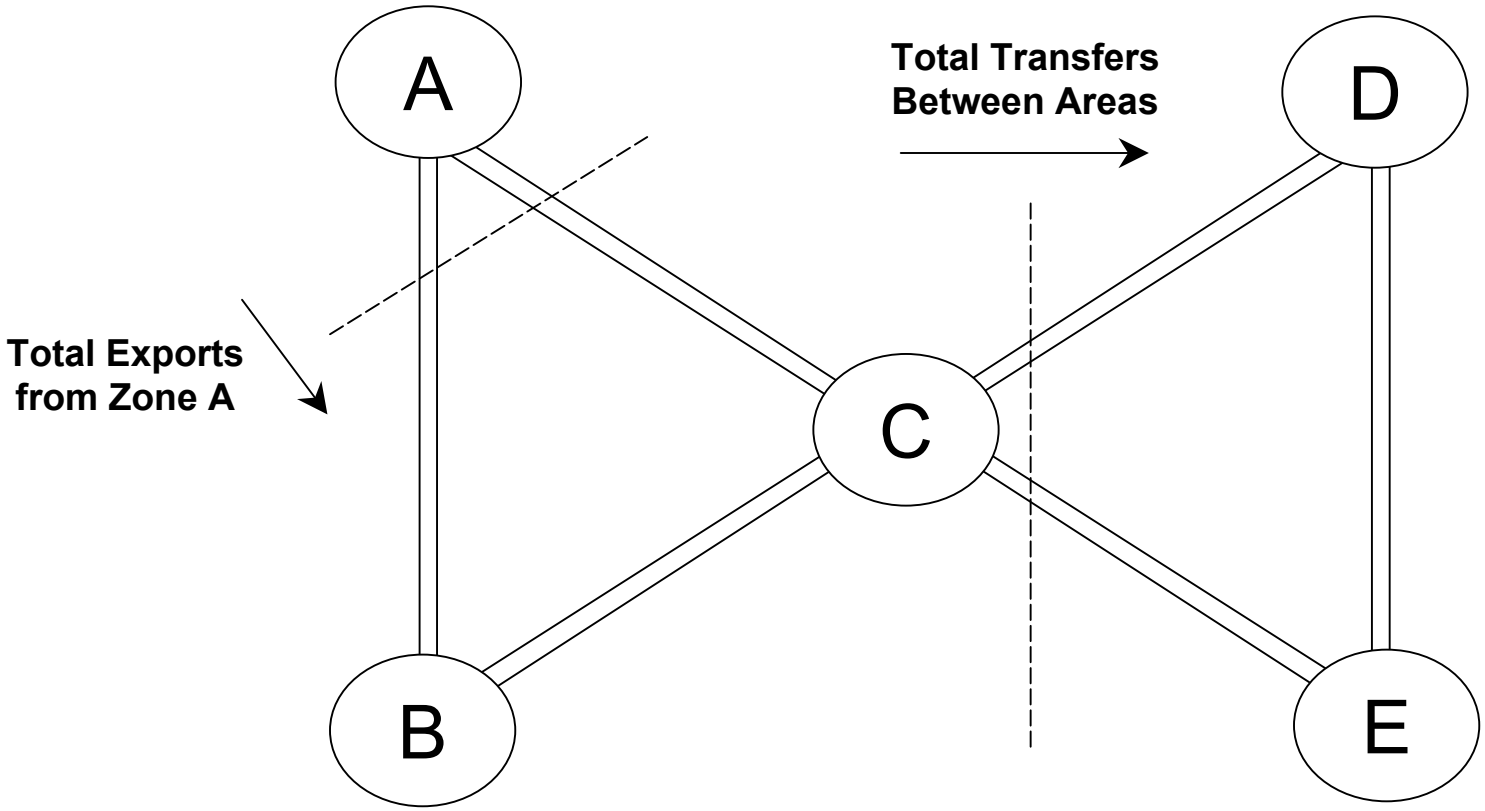
- **Assistance within Areas**
  - ***Zones with excess assist other zones in the same Area***
  - ***Option to block flow through outside Areas***
- **Assistance between Areas**
  - ***Specify arrangements between Area with excess and Area(s) receiving assistance***
  - ***Option to block flow through outside Areas***
- **System-wide assistance**

Resource Allocation Among Zones

- **Priority order**
  - ***Specify order in which zones with excess reserves provide assistance to zones that are deficient***
  - ***Priority given to zones within an Area***
- **Reserve sharing**
  - ***Excess resources allocated among deficient zones in proportion to zone shortfalls***
  - ***Iterative process to recognize interface transfer limits***
  - ***Assistance not delivered due to transfer limitations allocated according to input priority order***

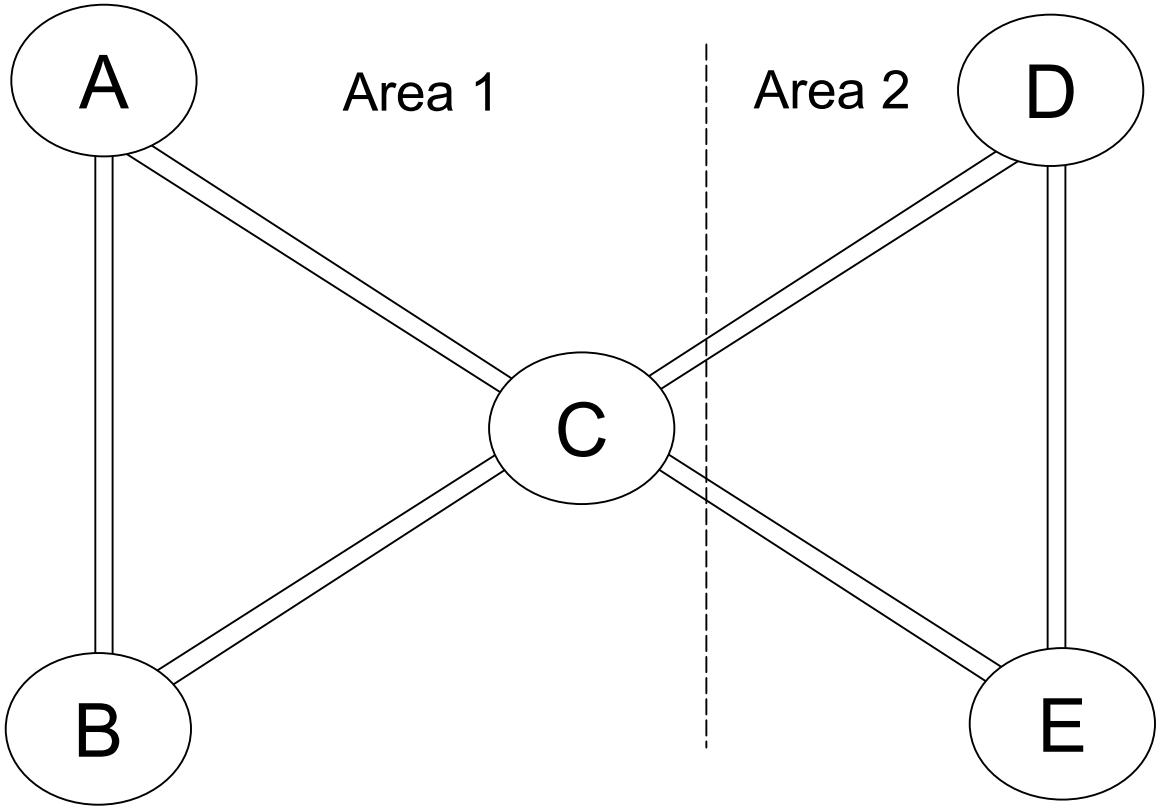
Transmission System Data

- **Limits on Simultaneous Interface Flows**
  - ***Limit Total Flow on Groups of Interfaces***
- **Dynamic Interface Transfer Limits**
  - ***Function of Available Units or Load Each Hour***



Transmission System Data

- **Define interfaces between zones**
  - ***Each interface consists of two ties***
- **Specify transfer limit of each tie**
  - ***Capacity states and interface transition rates***



Contracts (Firm or Curtailable)

- **Specify**
  - ***Hourly contract rating (type 2 energy-limited unit or DSM)***
  - ***Sending and receiving zones***
  - ***Interchange path for delivery***
- **Firm Contracts**
  - ***Scheduled regardless of available resources in the sending zone***
  - ***Curtailed only because of transfer limitations***
- **Curtailable contracts**
  - ***Scheduled to extent that sending zone has the necessary resources available from its own generation or assistance from other zones***
  - ***Curtailed due to insufficient resources or transfer limitations***
- **Summary of MWh and hours of curtailment**

Demand-Side Management

- **Modeled as zone load modifiers**
- **Specify net hourly load modification for a typical week (168 hours)**
  - ***Positive values decrease load***
  - ***Negative values increase load***
- **Create DSM programs from combination of devices**
  - ***Input hourly shapes in EEI format (8,760 hourly values) for each device***
  - ***Specify penetration levels by device***

Energy-Storage Units

- **Modeled as zone load modifiers**
- **Specify net hourly load modification for a typical week (168 hours)**
  - ***Positive values for generating***
  - ***Negative values for recharging***

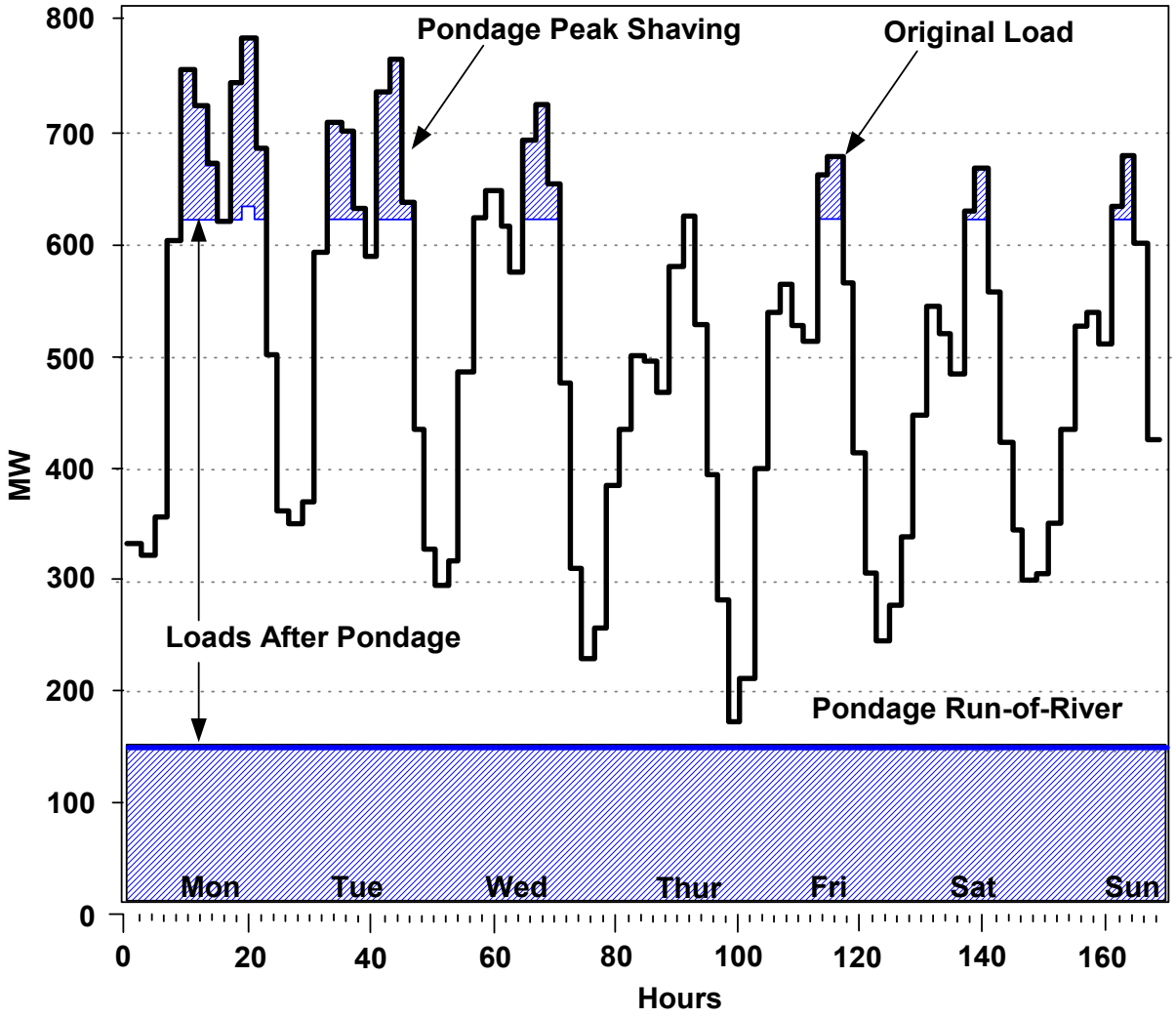
Type 2 - Energy-Limited Units

Peak-Shave Capacity - As Needed

- **Calculate isolated zone margins based on available thermal capacity**
- **Operate peak-shaving capacity in the zone, up to its capacity and energy limits**
  - ***To meet the zone's needs***
  - ***To provide assistance to other zones***
- **Unused energy carried forward to next month, subject to specified storage limitations**
  - ***No carry-forward from replication to replication, or year to year***

Type 2 - Energy-Limited Units

Peak-Shave Capacity - Deterministic



Transition Rates from F.O.R.

- **Input data**
  - ***Partial forced outage rates by capacity state***
  - ***Number of transitions between states***
- **Time in state calculated from outage rates**

State	MW	PFOR	Time in State
1	100	0.20	0.80
2	70	0.16	0.04
3	30	0.10	0.06
4	0	0.00	0.10

State Transition Rates

Example

State	MW	Hours
1	200	5000
2	100	2000
3	0	1000
Scheduled Outage Time		760
		8760

Transition Matrix

From State	To State 1	2	3
1	0	10	5
2	6	0	12
3	9	8	0

Transition Rates

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

State Transition Rates

- **Number of transitions from State A to State B per unit of time in State A**
- **$TR(A - B) = \dfrac{\text{Number of transitions from A to B}}{\text{Total time in State A}}$**
- **Used to determine**
  - ***Mean time in each state***
  - ***Probability of transitioning from each state to each other state***
- **Option to approximate from partial forced outage rates and number of transitions**

Thermal Unit Data

Includes Type 1 ELU and Cogen

- **Maximum rating in MW**
  - ***Derate based on zone load as an indicator of ambient temperature***
- **Rating of capacity states**
  - ***Up to 11 states for each unit***
- **Transition rates from each capacity state to each other capacity state**

Maintenance Scheduling

- **Fixed**
  - ***Specify starting/stopping month and day***
  - ***Thermal units limited to 2 periods per year***
- **Automatic**
  - ***Scheduled to levelize weekly MW reserves on zone, Area, or system basis***
  - ***Specify maintenance cycles (Planned Outage Rate or weeks of maintenance) and maintenance windows***
- **Maintenance schedule from previous run**

Unit Data

- **Name**
- **Unit type**
  - ***Thermal***
  - ***Energy-limited***
  - ***Cogeneration***
  - ***Energy storage***
  - ***Demand-side management***
- **Unit summary type**
- **Zone location**
- **Installation and retirement dates**
- **Planned maintenance requirements**

Load Forecast Uncertainty

- **Input up to 10 per unit multipliers on annual peak and corresponding probability of occurrence**
  - ***Per-unit multipliers input by zone***
  - ***Multipliers can change monthly, probabilities annually***
- **Reliability calculated for each load level**
- **Weighted-average value used to test convergence**

Load Data

- **Hourly load data input in EEI format for each zone for first year to be studied**
  - ***Optional input for subsequent years***
- **Load shapes modified to match specified monthly or annual peaks and energies**
- **Load adjustment options**
  - ***Hold monthly peak***
  - ***Hold monthly peak and valley***
  - ***Adjust daily shapes while holding daily peak***

Calculation of Indices

- **Basic calculations are done at the zone level**
  - ***Load is defined by zone, units are assigned to zones, and transfer limits are specified between zones***
  - ***Zone load is compared to available zone generation plus assistance from other zones***
  - ***If load exceeds generation plus assistance, zone is counted as being deficient***
- **Area indices are derived from the zones in that Area**
  - ***If one or more zones in the Area are deficient, the Area is counted as being deficient***
- **User can also define zone groupings for calculating indices**
  - ***Calculations continue to be done at the zone level***
  - ***If one or more zones in the zone group are deficient, the zone group is counted as being deficient***

Reliability Indices Calculated

- **Expected value and distribution of**
  - ***Daily LOLE (days/year)***
    - ***at time of each zone's daily peak, or***
    - ***at time of daily peak for specified zone or Area***
  - ***Hourly LOLE (hours/year)***
  - ***LOEE (MWh/year)***
  - ***Frequency (outages/year)***
  - ***Duration (hours/outage)***
- **Daily LOLE calculated for specified EOPS**
- **Indices available by zone, Area, and zone group on isolated and interconnected basis**

Sequential Monte Carlo Simulation

Simulation Process

- **Determine capacity available each hour from each unit on the system based on:**
  - ***Unit rating and capacity states***
  - ***Scheduled planned outages***
  - ***Random forced outages***
- **Sum available capacity in each zone**
- **Determine zone margins for each hour**
  - ***Margin = Capacity - Load***
- **Accumulate statistics for isolated indices**
- **Calculate flows between zones (if needed) and resulting zone margins**
- **Accumulate statistics for interconnected indices**
- **Proceed to the next hour**

MARS Methodology

- **Based on a full sequential Monte Carlo simulation**
- **Chronological system simulation performed by combining:**
  - ***Randomly generated operating histories of units through time***
  - ***Hourly chronological load cycles***
  - ***Transmission links***
- **Year simulated until convergence criterion is met**

Factors Influencing Convergence

- **Number of units and size of units relative to load**
  - ***Many units small in comparison to load results in less year-to-year variation and faster convergence***
- **Strength of transmission network between interconnected zones and Areas**
  - ***Strong ties reduce yearly variations***
- **Level of reliability**
  - ***Highly reliable systems converge more slowly***

Simulation Convergence

- **Degree of statistical convergence of reliability index measured by standard deviation of estimate of reliability index calculated from simulation**

$$I_i = \text{Value of reliability index obtained from simulation data for year i}$$

$$N = \text{Number of times year has been simulated}$$

$$\bar{I} = \sum_{i=1}^{N} I_i/N = \text{Estimate of expected value of index I}$$

$$S^2 = \sum_{i=1}^{N} \left[\left(I_i - \bar{I}\right)^2\right]/N = \text{Sample variance}$$

$$S_{\bar{I}} = \sqrt{\left(S^2/N\right)} = \text{Standard deviation of estimate } \bar{I}$$

$$S_{\bar{I}}/\bar{I} = \text{Standard error of estimate } \bar{I}$$

Monte Carlo Simulation for Reliability Evaluations

- **Random events to be considered**
  - ***Equipment forced outages***
  - ***Variations in forecasted loads***
- **System scenario created by randomly drawing availability of equipment and load demand**
- **Reliability indices determined for given scenario**
- **Year is simulated with different sets of random events until statistical convergence is obtained**

Multi-Area Reliability Simulation Program (MARS)

- **Developed for utilities of New York State**
- **Model any number of zones and Areas**
- **Typical applications include:**
  - ***Resource Adequacy Assessments***
  - ***Locational Capacity Requirements***
  - ***Benefits of Diversity***
  - ***Tie-line Effectiveness***
  - ***Need for EOPs***

MARS: The Primary Reliability Calculation Tool

New York State Reliability Council

July 11, 2003

Glenn Haringa

GE-PSEC