## Loss of Load Expectation (LOLE) 101 Sections

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Loss of Load Expectation (LOLE) Definition

LOLE is the measure of how long, on average, the available generation capacity is likely to fall short of the load demand.

| Loss of Load Probability (LOLP) is the probability in a given hour | Sum of the Daily Peak LOLP values is an expectation (LOLE) | Sum of all LOLP values is called Loss of Load Hours (LOLH) |

LOLE is used to study Generation (Resource) Adequacy

Generally considered to be the existence of sufficient resources, within a system, to satisfy consumer demand. A product of unit availability, “perfect storm.” The study of low probability, high impact events.
1-day in 10-years LOLE Criteria

MISO Resource Adequacy criteria for Planning Reserve target is the industry standard LOLE objective: <1-day in 10-years

NERC Standard BAL-502-RF-03
• Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year analyzed being equal to 0.1. (This is comparable to a “one day in 10 year” criterion).
Common Terminology Misconceptions

- 1 day in 10 years LOLE ≠ 24 hours in 10 years LOLH.
  - Example: 2 hours of firm load shed = 2 loss of load hours and 1 day of loss of load.
  - By definition 1 day/10 years LOLE ≤ 24 hours/10 years LOLH.

- Cannot calculate Loss of Energy Expectation (LOEE) from LOLH without running complete analysis.
LOLE Connections to Various MISO Processes

LOLE

- Planning Reserve Margin (PRM) Study
  - Resource Adequacy
    - Tariff Module E-1
    - Capacity Market
  - Planning Studies
    - Resource Forecasting
    - MTEP Study
- Assessments
  - NERC Assessments
  - MISO Informational Forums
Resource Adequacy Overview

- Achieving reliability in the bulk electric systems requires that the amount of resources exceeds customer demand by an adequate margin.

Margins necessary to promote Resource Adequacy need to be assessed on:

- **Longer-term planning basis**
  - Focus of MISO’s RA Construct is on the longer-term planning margins used to provide sufficient resources to reliably serve load on a forward-looking basis.

- **Near-term operational basis**
  - Resources dedicated to meet Demand have an obligation to be available to meet real-time customer demand and contingencies.
Planning Reserve Margins (PRMs)

Planning Reserve Margins must be sufficient to cover:

- Planned maintenance
- Variations in customer demands or forecast demand uncertainty
- Unplanned or forced outages of generating equipment
- System effects due to reasonably anticipated variations in weather
- Deratings in the capabilities of Generation resources and Demand Response Resources

LOLE Study Connections to other MISO Processes
Overview of MISO Resource Adequacy Requirements

Peak Demand and Planning Reserve Margin

Generation, Load, and Resource Credits

PRMR

LSE Obligation

Planning Resources
“For capacity planning and reliability study purposes, all generating facilities declared as capacity resources in the MISO market are required to submit GADS event and performance data to determine the value of the facility as an unforced capacity resource.”
GADS Data Requirements...

- **Generation Resources**
- **External Resources**
- **Demand Response Resources backed by behind the meter generation**
- **or Behind the Meter Generation (BTMG)**

**Greater than or equal to 10 MW, based on Generation Verification Test Capacity (GVTC)**

- Must submit generator availability data (including, but not limited to, NERC GADS) into PowerGADS through the Market Portal

**Less than 10 MW, based on (GVTC), that begin reporting generator availability data**

- Must continue to report such information
GADS Data Requirements…

• Quarterly Submittal of Data
  • Stakeholders are expected to submit data on a quarterly basis
  • Quarterly GADS data must be received by the last day of the month following the operating quarter
  • Quarterly GADS data must be Level 2 Validated by the last day of the month following the operating quarter
GADS Data Requirements…

- A unit will receive 100% EFORd if it fails to submit GADS data and successfully Level 2 Validate

- Assigning 100% EFORd will impact a unit’s unforced capacity calculation
  - \[ \text{UCAP} = \text{GVTC} \times (1 - EFORd) \]
Three Types of Data are to be Collected…

**Event Data**
- Each time a unit has a change in operating status or capability, an *event* is recorded
- From these event reports a unit’s operational history can be reconstructed

**Generation Performance Data**
- A unit’s actual generation, hours of operations, and operational characteristics

**Fuel Performance Data (optional)**
- A unit’s actual fuel consumption and fuel quality data
PowerGADS – Event Data

Event data – to be collected:

- Event Number
- Event Type
- Start of Event
- End of Event (Can be blank if event is ongoing)
- Net Available Capacity
- Primary Cause Code
- Additional Cause Code (Optional)
- Event Contribution Code
  - describes impact or contribution that this cause or component had on the event
- Verbal Description (Optional)
- Failure Code (Optional)
PowerGADS – Performance Data

Performance data – to be collected:

- Net Maximum Capacity
- Net Dependable Capacity
- Net Actual Generation
- Typical Unit Loading Code
- Loading Verbal Description (If Typical Unit Loading Code is 6)
- Attempted Unit Starts
- Actual Unit Starts
- Unit Service Hours
- Reserve Shutdown Hours
- Pumping Hours
- Synchronous Condensing Hours
PowerGADS – Event Types

Active

Available (Zero to Full Load)

Available

Unavailable (No Load)

Unavailable

Reserve (Not Connected)

In Service (Connected)

Planned Deratings

No Deratings (NC)

Unplanned Deratings

Planned Deratings

No Deratings

Unplanned Deratings

Planned Outage

Unplanned Outage

Planned Outage

Unplanned Outage

PD

DP

D4

DM

D1

D2

D3

PO

PE

MO

ME

U1

U2

U3

SF
LOLE Model Inputs Include:

**Study System**
- Zone & Pool definition
- External Tie Limits
- External System Model

**Generation Resources**
- Operating Parameters
- Unit Forced Outage Rates
- Planned Maintenance Schedules & Rates
- Dispatch Limits for DR and Interruptible Load

**Load**
- Demand and Energy Forecast
- Load Shape/Profile
- Load Uncertainty

**LOLE Model Inputs**
Source of LOLE Model Input Data

**Generation Resources**
- Generator Availability Data System (GADS)
  - Unit performance statistics used to calculate forced outage rates
  - Data is uploaded into the MISO system one month after end of each quarter
- Generation Verification Test Capacity (GVTC)
  - Units need to demonstrate maximum output level

**Load**
- Load training using historical load and weather data
- Monthly Peak Demand, MISO Coincident Demand and Energy Forecast are uploaded by Load Serving Entities (LSEs) into the Module-E Capacity Tracking (MECT) Tool (deadline Nov. 1st)
- MISO reviews Forecast and Finalize review by March
MISO System LOLE Model

Firm External

LRZ-10
LRZ-1
LRZ-2
LRZ-3
LRZ-4
LRZ-5
LRZ-6
LRZ-7
LRZ-8
LRZ-9
LRZ-10

MISO Hub
Local Resource Zone LOLE Model

LRZ-1
LRZ-2
LRZ-3
LRZ-4
LRZ-5
LRZ-6
LRZ-7
LRZ-8
LRZ-9
LRZ-10
MISO uses the Strategic Energy Risk Valuation Model (SERVM) Software

Managed by Astrapé Consulting

Originated within Southern Company back in the early 1980’s

Uses a sequential Monte Carlo simulation

- Steps through time chronologically and randomly drawing unit availability
- Replicating simulation with different sets of random events until statistical convergence is obtained

SERVM resource adequacy metrics consider

- Wide Variation of Load Shapes
- Growth Uncertainty
- Unit Performance

Utilizes a SQL Server database
Analytical vs. Monte Carlo approach to analysis

- Analytical methods work well for small systems and represent a system using mathematical model (A direct mathematical solution).

- Monte Carlo methods simulate the actual process and repeat simulation until convergence criteria is met.

- For complex systems, a Monte Carlo “brute force” approach is more appropriate.
Types of Monte Carlo Analysis

- **Non-Sequential Monte Carlo Simulation**
  - Each hour is independent of every other hour
  - Inability to model time-correlated issues.
  - Inability to calculate frequency and duration indices.

- **Sequential Monte Carlo Simulation**
  - Steps through time chronologically.
  - Ability to model time correlated issues and calculate frequency and duration indices.
  - Requires more detailed system data.
Utilized SERVM Characteristics

- Multi Area Model
- Multiple Weather Years (supports up to 50 years)
- Detailed DR Representation
- Granular LOLE Calculations
Additional SERVM Characteristics

- Renewable Generation Modeling
- Transportation model to represent multiple neighbors and interconnections
- Full Economic Dispatch of Resources Allowing for Dispatch Constraints on Resources
- Alternative Dispatch During Reliability Events
- Operating Reserves Modeled Based on NERC Guidelines
- Economic Calculations
- Scarcity Pricing Algorithms
- Production Costing Ability
Utilized SERVM Modeling Components

- Weather Years
  - Multiple load shapes
- Economic Load Forecast Error (LFE)
- Unit Outage Modeling
- Energy Limited Resource Modeling
  - Demand Side Options
Additional SERVM Modeling Components

- Weather Years
  - Thermal Capacity/Hydro
- Energy Limited Resource Modeling
  - Hydro and Pump Storage
  - Renewable resources (i.e. Wind & Solar)
- Scarcity Pricing, Neighbor Modeling, and Transmission Modeling
- Emergency Operating Procedures
Importance of Load Modeling in LOLE Analysis

• Loss of Load Expectation analysis is largely driven by two factors
  • Generation Uncertainty
  • Load Uncertainty

• Accurately capturing uncertainty is crucial to LOLE analysis

• Load Uncertainty
  • Load Shape
  • Weather Uncertainty
  • Economic Uncertainty
Load Modeling Framework

- Use historic weather years to capture load uncertainty
  - Variance in peak demand
  - Variance in load shape

- Results in more diverse and comprehensive load modeling
  - More accurate shoulder and non-peak load variance and uncertainty

- Utilize Neural-Net software to “train” data
Load Training Process

1. Historical load and weather data formatting
2. 5-year load growth adjustment
3. Neural-net training
4. Neural-net predicting
5. Extreme temperature adjustment
6. Load forecast adjustment
Data Sources for Load Training

- Historical real-time settlement load data
  - Source: MISO
  - 2012 to 2016
- Historical real-time LMR performance
  - Source: MISO
  - Voluntary and MISO deployments
  - 2015-2016
- Historical weather data
  - Source: NOAA
  - 1981 to 2016
- LSE load forecasts
  - Source: LSE submittals to MECT
Historical Load and Weather Formatting

- 5 years of hourly load and temperature (2012-2016)
- Weather data (2012-2016)
  - Month
  - Temperature
  - Time of Day
  - Day of Week
  - 24 hour ago Temperature
  - 48 hour ago Temperature
- Holidays are set to Sunday
  - January 1\textsuperscript{st}
  - July 4\textsuperscript{th}
  - December 25\textsuperscript{th}
5-Year Load Growth Adjustment

- 5 years of load data should not include load growth due to economics

- Load normalized to consistent economics

- Adjustment calculated based off high temperature load analysis i.e. 90 degrees and above
Neural-Net Training

- Ward Systems Group Software
- Used for pattern recognition of multi-variable problems
- Makes predictions based off of established neural-net functional relationships

- Input Variables
  - Month
  - Day of week
  - Time of day
  - Previous hour load
  - Temperature
  - 24 hour ago temperature
  - 48 hour ago temperature

- Output Variables
  - Actual Load

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Neural-Net Training

![Graph showing actual and predicted values over time.]

**Best net statistics**
- $R^2$: 0.996521
- Avg. Error: 91.26518
- Correlation: 0.99829
- MSE: 13960.78
- RMSE: 118.1557
- % in range: 0.0%
- % same sign: 100.0%

![Bar chart for the best net statistics with values: Hour 0.424, Temperature 0.071, Previous Hour Load 0.423, 24% Ago Temp 0.022, 48% Ago Temp 0.015, Day of Week Inci Holidays 0.046.]
Neural-Net Predicting

- 36 years of historical weather
  - 1981 to 2016

- Neural-Net applied to 36 years of historical weather to predict load

- Output is 36 weather year load shapes at 5 year normalized economy
  - i.e. Predicted 2016 load with 1990 weather
Extreme Temperature Verification

- Verify load training at extreme temperatures is accurate
- Less data points at temperature extremes for neural-net training
Load Forecast Adjustment

• Average of 36 predicted load shapes adjusted to match LRZ’s 50/50 zonal peak load forecast for study year

• Ratio of 1\textsuperscript{st} years Non-Coincident Peak Forecast to Zonal Coincident Peak Forecast applied to future years Non-Coincident Peak Forecast

• Results in 36 Planning Year weather load shapes
  • i.e. 2018-19 PY load if we have 1995 weather
Economic Load Forecast Error

- Use Projected and Actual GDP Growth Rates for Economic Uncertainty
  - Use Congressional Budget Office (CBO) projections for GDP growth (historic)
  - Compare with the actual GDP growth taken from the Bureau of Economic Analysis
  - Translate the GDP forecast error into electric utility forecast error by multiplying by a scalar
    - Rate at which electric load grows in comparison to GDP
  - Calculate the standard deviation of forecast error
  - Using the standard deviation, create a normal distribution of forecast error
## Example of Economic Load Forecast Errors

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<th>SD in LFE</th>
<th>LFE Levels</th>
<th>Probability to Assign to Each LFE</th>
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<td>4.14%</td>
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Advantages in Load Modeling with historical weather

- Multiple load shapes based on weather more accurately capture
  - Variance in load shapes
  - Variance in peak load
  - Seasonal load uncertainty
  - Frequency and duration of severe weather patterns

- Decouple weather and economic uncertainty
Unit Data

- Unit Name
- Unit Physical Local Resource Zone (LRZ)
- Installation Date
- Retirement Date
- Type (Thermal, Curtailable Load, Renewable)
- Unit Summary Type
  - Thermal (Nuclear, Fossil Steam, Combustion Turbine, Hydro, Pumped Storage Hydro)
  - Curtailable Load (Demand Response and Energy Efficiency)
  - Renewable (Intermittent Resources such as Wind, Run-of-River Hydro, and Biomass)
- Thermal Units
  - Utilize the Generator Verification Test Capacity (GVTC) for a peak capacity and each unit’s monthly Net Dependable Capacity (NDC) submitted in PowerGADS determines each unit’s monthly capacity profile
Forced Outage Rates & Unit Maintenance – Thermal Units Only

- Forced Outage Rates
  - Time to Repair
  - Time to Failure

- Fixed Maintenance – Typically Nuclear Units
  - Begin Date
  - Stop Date

- Planned Outage Rates
  - Percentage of the year in which a unit will be on scheduled maintenance
  - Planned Outage Factor + Maintenance Outage Factor from PowerGADS

- Maintenance scheduled on days with maximum reserves
Curtailable Load Units (Energy Limited)

- SERVM dispatches Demand Response (DR) & Energy Efficiency (EE) based on several constraints
  - Days per week
  - Hours per day
  - Hours per year
  - Dispatch price
- Use limitations to model fatigue
  - Minimum Megawatt (MW) – Zero
  - Maximum Megawatt (MW) – Monthly Profile
Demand Side Management (DSM)

- Renewable Units (Wind, Run-of-River Hydro, and Biomass)
- Net Hourly Load Modification
  - Maximum Megawatt (MW) – Monthly Profile
  - Positive values decrease load
Non-Firm Support

- Represents benefit of being part of Eastern Interconnect

- 1 MW of non-firm support reduces requirement by 1 MW

- Reliability targets highly sensitive to fluctuations in non-firm support

- LOLE study uses set MW amount of non-firm
Firm Imports

- External resources FRAP’ed or Offered in MECT are included in LOLE modeling.
- External purchases are modeled similar to MISO units.
- Modeled from external region to MISO.
- Firm imports are only modeled in MISO PRM model and not zonal LRR model.
- External firm imports impact LOLE based on unit characteristics
Firm Exports/Sales

- Capacity that is ineligible for MISO PRA is excluded from MISO and zonal models.
- Only units that have capacity obligations outside of MISO are designated as sold in the LOLE model.
- External firm exports impact LOLE based on unit characteristics
**SERVM Simulation Frameworks**

36 Weather Years (equal probability) \( \times \) 3 Economic Uncertainties (Normal Distribution) = 108 Load Scenarios

108 Load Scenarios \( \times \) 1,000 unit outage draws = 108,000 8760 hour simulations

**Scenarios are an example of framework and are not fixed**
Capacity Adjustment Flowchart

1. Add Perfect (Zero EFORd) Negative Unit
2. Add Proxy Unit w/ Class Average Forced Outage Rate
3. Run SERVM w/ MISO System As Is
4. Check LOLE for Planning Year [June – May]
5. Determine Planning Reserve Margins

- LOLE < 0.1
- LOLE > 0.1
- LOLE = 0.1
- Does output of LOLE = 0.1
LOLE Study Deliverables to MISO’s Planning Resource Action (PRA)

- The LOLE study has four deliverables to the Planning Resource Auction
  - MISO PRM UCAP [%]
  - Local Resource Zones (LRZ) Local Reliability Requirement (LRR) per unit
  - LRZ Capacity Import Limit (CIL)
  - LRZ Capacity Export Limit (CEL)
- LOLE deliverables are applied to updated demand forecasts to calculate PRA requirements
# Calculation of MISO PRM [%]

<table>
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<th>2017/2018 PY</th>
<th>Formula Key</th>
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<td>[A]</td>
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<tr>
<td>Installed Capacity (ICAP) (MW)</td>
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<tr>
<td>Unforced Capacity (UCAP) (MW)</td>
<td>140,226</td>
<td>[C]</td>
</tr>
<tr>
<td>Firm External Support ICAP (MW)</td>
<td>4,529</td>
<td>[D]</td>
</tr>
<tr>
<td>Firm External Support UCAP (MW)</td>
<td>4,349</td>
<td>[E]</td>
</tr>
<tr>
<td>Adjustment to ICAP (MW)</td>
<td>(4,577)</td>
<td>[F]</td>
</tr>
<tr>
<td>Adjustment to UCAP (MW)</td>
<td>(4,577)</td>
<td>[G]</td>
</tr>
<tr>
<td>ICAP PRM Requirement (PRMR) (MW)</td>
<td>150,867</td>
<td>[H] = [B]+[D]+[F]</td>
</tr>
<tr>
<td>UCAP PRM Requirement (PRMR) (MW)</td>
<td>139,998</td>
<td>[I] = [C]+[E]+[G]</td>
</tr>
<tr>
<td>MISO PRM ICAP</td>
<td>18.1%</td>
<td>[J]=[H]-[A]/[A]</td>
</tr>
<tr>
<td>MISO PRM UCAP</td>
<td>9.63%</td>
<td>[K]=[I]-[A]/[A]</td>
</tr>
</tbody>
</table>

**Post-Processing accounting for non-firm external support**

<p>| | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
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</tr>
</thead>
<tbody>
<tr>
<td>External Non-Firm Support ICAP (MW)</td>
<td>2987</td>
<td>[L]</td>
</tr>
<tr>
<td>External Non-Firm Support UCAP (MW)</td>
<td>2331</td>
<td>[M]</td>
</tr>
<tr>
<td>With External Support ICAP PRM Requirement (MW)</td>
<td>147,880</td>
<td>[N]=[B]+[D]+[F]-[L]</td>
</tr>
<tr>
<td>With External Support UCAP PRM Requirement (MW)</td>
<td>137,667</td>
<td>[O]=[C]+[E]+[G]-[M]</td>
</tr>
<tr>
<td>With External Support MISO PRM ICAP</td>
<td>15.8%</td>
<td>[P]=([N]-[A])/[A]</td>
</tr>
<tr>
<td>With External Support MISO PRM UCAP</td>
<td>7.8%</td>
<td>[Q]=([O]-[A])/[A]</td>
</tr>
</tbody>
</table>
## Calculation of Zonal Requirements and Example PRA Requirements

<table>
<thead>
<tr>
<th>Local Resource Zone (LRZ)</th>
<th>LRZ-1 MN/ND</th>
<th>LRZ-2 WI</th>
<th>LRZ-3 IA</th>
<th>LRZ-4 IL</th>
<th>LRZ-5 MO</th>
<th>LRZ-6 IN</th>
<th>LRZ-7 MI</th>
<th>LRZ-8 AR</th>
<th>LRZ-9 LA/TX</th>
<th>LRZ-10 MS</th>
<th>Formula Key</th>
</tr>
</thead>
<tbody>
<tr>
<td>Installed Capacity (ICAP)</td>
<td>18,984</td>
<td>15,465</td>
<td>10,759</td>
<td>11,683</td>
<td>8,674</td>
<td>19,853</td>
<td>23,642</td>
<td>11,273</td>
<td>23,444</td>
<td>7,090</td>
<td>[A]</td>
</tr>
<tr>
<td>Unforced Capacity (UCAP)</td>
<td>17,984</td>
<td>14,584</td>
<td>10,164</td>
<td>10,443</td>
<td>7,840</td>
<td>18,547</td>
<td>21,828</td>
<td>10,716</td>
<td>21,602</td>
<td>6,473</td>
<td>[B]</td>
</tr>
<tr>
<td>Adjustment to ICAP</td>
<td>2,438</td>
<td>-89</td>
<td>790</td>
<td>1,968</td>
<td>2,366</td>
<td>1,017</td>
<td>3,005</td>
<td>-400</td>
<td>1,672</td>
<td>585</td>
<td>[C]</td>
</tr>
<tr>
<td>Adjustment to UCAP</td>
<td>2,293</td>
<td>-89</td>
<td>743</td>
<td>1,851</td>
<td>2,225</td>
<td>957</td>
<td>2,827</td>
<td>-400</td>
<td>1,573</td>
<td>550</td>
<td>[C]</td>
</tr>
<tr>
<td>LRR (UCAP)</td>
<td>20,277</td>
<td>14,495</td>
<td>10,907</td>
<td>12,294</td>
<td>10,066</td>
<td>19,504</td>
<td>24,654</td>
<td>10,316</td>
<td>23,175</td>
<td>7,023</td>
<td>[D]=[B]+[C]</td>
</tr>
<tr>
<td>Peak Demand</td>
<td>18,215</td>
<td>12,982</td>
<td>9,695</td>
<td>10,013</td>
<td>8,262</td>
<td>17,457</td>
<td>21,607</td>
<td>8,198</td>
<td>20,733</td>
<td>4,975</td>
<td>[E]</td>
</tr>
<tr>
<td>LRR UCAP per-unit of LRZ Peak Demand</td>
<td>111.3%</td>
<td>111.7%</td>
<td>112.5%</td>
<td>122.8%</td>
<td>121.8%</td>
<td>111.7%</td>
<td>114.1%</td>
<td>125.8%</td>
<td>111.8%</td>
<td>141.2%</td>
<td>[F]=[D]/[E]</td>
</tr>
</tbody>
</table>

### 2017-2018 Planning Reserve Margin (PRM) Study

- **Installed Capacity (ICAP)**
- **Unforced Capacity (UCAP)**
- **Adjustment to ICAP**
- **Adjustment to UCAP**
- **LRR (UCAP)**
- **Peak Demand**
- **LRR UCAP per-unit of LRZ Peak Demand**
Important LOLE Fundamentals

Takeaways

- LOLE is the measure of how long, on average, the available generation capacity is likely to fall short of the load demand
  - LOLE is used to study Generation(Resource) Adequacy
  - Probabilistic analysis accurately captures uncertainty risk
- MISO Resource Adequacy criteria for Planning Reserve target is the industry standard LOLE objective:
  - 1-day in 10-years
  - Aligns with NERC standards
- Achieving reliability in the bulk electric systems requires that the amount of resources exceeds customer demand by an adequate margin (Planning Reserve Margin)
  - LOLE models utilize an Equivalized Transportation Model to determine Planning Reserve Margin and Local Reliability Requirements
- All Market Participants are encouraged to participate in the stakeholder process through LOLEWG
Reference Materials

• Past LOLE 101 Documents
  • LOLE Fundamentals (May 4th, 2016)
  • 2016 Capacity Accreditation Workshop

• Loss of Load Expectation Reports
  • Loss of Load Expectation (LOLE) Study Reports
  • Loss of Load Expectation Working Group (LOLEWG)
  • 2017 Wind Capacity Report

• Resource Adequacy Documents
  • BPM
    • BPM 011 - Resource Adequacy
  • MISO Tariff: Module E-1
  • NERC Standard BAL-502-RF-03
LOLE Terms and Definitions

- **Installed Capacity**: The installed capacity that is physically located within the zone. The ICAP is the output that the generator tested for its max summer output.

- **Unforced Capacity**: The installed capacity less forced outage rates. Capacity Resources are quantified by applying forced outage rates to installed capacity values (ICAP) to calculate the Unforced Capacity value (UCAP) for the resource.

- **Adjustment to UCAP**: The UCAP capacity adjustment within the zone to drive the zone to the “1 day in 10” criteria if the zone was an island. If a zone is more reliable than “1 day in 10” capacity needs to be removed in order to drive the model to the LOLE metric.

- **LRR (UCAP)**: Zonal specific reserve margin requirement [MW], capacity above zonal peak load, required to meet “1 day in 10” loss of load expectation requirement if the Local Resource Zone is an island (i.e. completely disconnected from external areas and the rest of MISO.)
LOLE Terms and Definitions

- **Peak Demand**: The zone’s annual peak demand.
- **Time of Peak Demand (ESTHE)**: The date and time of the zone’s annual peak demand.
- **LRR UCAP per-unit of LRZ Peak Demand**: Zonal specific reserve margin [%], capacity above zonal peak load, required to meet “1 day in 10” loss of load expectation requirement if the Local Resource Zone is an island (i.e. completely disconnected from external areas and the rest of MISO).
- **Capacity Import Limit**: The amount of capacity that a zone can import from outside their zone reliably during peak load before observing a transmission constraint.
- **Capacity Export Limit**: The amount of capacity that a zone can reliably export out of their zone during peak load before observing a transmission constraint.
- **Forecasted LRZ Load at MISO Peak**: Zone’s load coincident with MISO’s annual peak load.
LOLE Terms and Definitions

- **Local Reliability Requirement**: Zonal specific reserve margin requirement [MW], capacity above zonal peak load, required to meet “1 day in 10” loss of load expectation requirement if the Local Resource Zone is an island (i.e. completely disconnected from external areas and the rest of MISO.)

- **Local Clearing Requirement**: The minimum capacity required to be physically located within a zone to meet the “1 day in 10” Loss of Load Expectation requirement. The LCR is LRR minus the CIL and non-pseudo tied exports.

- **Zone’s System Wide PRMR**: The zones share of the total MISO Planning Reserve Requirement that the zone needs to procure on a UCAP basis [MW]. The difference of the zones system wide PRMR minus the Local Clearing Requirement is the capacity that can be cleared outside of the zone (able to import at peak load) to meet the Planning Reserve Margin Requirement.

- **Planning Reserve Margin (PRM)**: The reserve margin, capacity above peak load, the entire MISO footprint needs to procure to meet the “1 day in 10” Loss of Load Expectation requirement. The “1 day in 10” Loss of load requirement is the industry standard risk metric.
PRM and LRR Calculations

PRM ICAP = \frac{[\text{Installed capacity} + \text{ICAP Adjustment to meet 0.1 days/year LOLE + Firm Contracts}] - \text{MISO Peak Demand}}{\text{MISO Peak Demand}}

PRM UCAP = \frac{[\text{Unforced capacity} + \text{UCAP Adjustment to meet 0.1 days/year LOLE + Firm Contracts}] - \text{MISO Peak Demand}}{\text{MISO Peak Demand}}

Each LRZ’s LRR = \frac{\text{LRZ Unforced Capacity} + \text{LRZ UCAP Adjustment needed to meet 0.1 d/y LOLE}}{\text{LRZ Peak Demand}}

LRZ per unit LRR = \frac{\text{LRR}}{\text{LRZ Peak Demand}}