This presentation contains certain statements that describe our management’s beliefs concerning future business conditions and prospects, growth opportunities and the outlook for our business and the electricity transmission industry based upon information currently available. Such statements are “forward-looking” statements within the meaning of the Private Securities Litigation Reform Act of 1995. Wherever possible, we have identified these forward-looking statements by words such as “anticipates”, “believes”, “intends”, “estimates”, “expects”, “projects” and similar phrases. These forward-looking statements are based upon assumptions our management believes are reasonable. Such forward-looking statements are subject to risks and uncertainties which could cause our actual results, performance and achievements to differ materially from those expressed in, or implied by, these statements, including, among other things, the risks and uncertainties disclosed in our annual report on Form 10-K and our quarterly reports on Form 10-Q filed with the Securities and Exchange Commission from time to time.

Because our forward-looking statements are based on estimates and assumptions that are subject to significant business, economic and competitive uncertainties, many of which are beyond our control or are subject to change, actual results could be materially different and any or all of our forward-looking statements may turn out to be wrong. They speak only as of the date made and can be affected by assumptions we might make or by known or unknown risks and uncertainties. Many factors mentioned in our discussion in this presentation and in our annual and quarterly reports will be important in determining future results. Consequently, we cannot assure you that our expectations or forecasts expressed in such forward-looking statements will be achieved. Actual future results may vary materially. Except as required by law, we undertake no obligation to publicly update any of our forward-looking or other statements, whether as a result of new information, future events, or otherwise.
## Agenda

<table>
<thead>
<tr>
<th>Time</th>
<th>Event</th>
</tr>
</thead>
<tbody>
<tr>
<td>10:00 a.m.</td>
<td>Welcome remarks</td>
</tr>
<tr>
<td>10:05 a.m. – 11:15 a.m.</td>
<td>Presentations:</td>
</tr>
<tr>
<td></td>
<td>• EEI Review</td>
</tr>
<tr>
<td></td>
<td>• Protective Relay Maintenance and Replacement Program</td>
</tr>
<tr>
<td></td>
<td>• Planning Overview – Modeling, Analysis, &amp; Timeline</td>
</tr>
<tr>
<td>11:15 – 12:30 p.m.</td>
<td>Break &amp; Lunch</td>
</tr>
<tr>
<td>12:30 p.m. – 1:30 p.m.</td>
<td>Presentations:</td>
</tr>
<tr>
<td></td>
<td>• New NERC Requirements for Transmission Operators</td>
</tr>
<tr>
<td></td>
<td>• Internal Controls</td>
</tr>
<tr>
<td>1:30 p.m. – 2:00 p.m.</td>
<td>Break</td>
</tr>
<tr>
<td>2:00 p.m. – 3:00 p.m.</td>
<td>Presentations:</td>
</tr>
<tr>
<td></td>
<td>• Michigan Voltage Profile</td>
</tr>
<tr>
<td></td>
<td>• Frequency Response/Governor Control Update for Generation Status</td>
</tr>
<tr>
<td>3:00 p.m.</td>
<td>Closing remarks</td>
</tr>
</tbody>
</table>

*We hope you will join us back here for networking this evening starting at 7 p.m. followed by the Dr. Grins Comedy Show!*
CONNECTING
Energy Infrastructure
EEI Review
Rob Wrona
Manager, Operations Support
Questions?
Transmission Protective Relays

- Protective relays automatically operate transmission circuit breakers in milliseconds to isolate (de-energize) a faulted portion of the grid. This protects that portion of the grid from further damage and leaves it in a safer condition, as well as preserving the integrity of the rest of the grid.

- Relays are a “Silent Sentinel.” This means that they observe the grid 24/7 and are normally not performing any controlling function until they detect abnormal faulted system conditions.

- Relays can wait for years before being called upon to operate. In addition, microprocessor relays are assumed to have a life span of 20 to 30 years.
ITC Protective Relay Facts

- Multiple relays are organized in functional “schemes.” Each scheme has anywhere from one to six relays.

- The table on the right shows ITCT and METC total scheme counts (approx. 2700 ITCT and 2000 METC).

- ITCT has 3930 actual transmission relays and METC has 3160 relays in 270 substations protecting over 8700 circuit miles of transmission.
Why do we perform maintenance?

• To ensure reliable operation of the bulk electric system by ensuring relays will operate correctly when called upon.

• To conform with the mandatory regulatory reliability requirements stipulated by FERC under order 693. Specifically PRC-005 (Protective Relay Maintenance).
• Complete periodic maintenance is performed on a 10-year basis (i.e. 10% of the total ITC relay schemes are tested every year).

• These require a total local system shutdown to perform that activity (required to access energized equipment and for ITC safety and human performance requirements).

• System shutdowns are typically around three days.
• Each transmission owner, any distribution provider that owns a transmission protection system, and each generator owner that owns a generation protection system shall have a maintenance and testing program for protection systems that affect the reliability of the BES.

• The mandatory tested elements include:
  • Relays
  • Current Transformers
  • Voltage Transformers
  • DC Control Circuitry
  • Batteries
  • Communication Systems
ITC Relay Replacement Program

• ITC’s relay replacement program supports reliable protection system performance by replacing outdated protection systems, leveraging those assets for reliable system performance. The program reduces the potential for failed operations, increases reliability of protection systems, and increases system monitoring and event recording capabilities.

• This program strives to replace our protection systems at an annual pace, which targets each relay’s estimated end-of-life, taking into consideration the total number of protection systems and assuming a relay’s 30-year life cycle.
ITC Relay Replacement Activities

- Requires local system shutdown to perform activity (required to access energized equipment and for ITC safety and human performance requirements).
- System shutdowns can be up to several weeks, in some cases requiring extensive changes.
ITC - Making The Grid More Reliable
Questions?
Planning Overview – Modeling, Analysis & Timeline

Carlo Capra
Director, Planning
Agenda

- Model Building
  - Overview
  - NERC Requirements
  - Timelines
- Facility Ratings
- MISO Planning Coordination
  - Roles & Responsibilities
  - Bottom Up / Top Down
  - Planning Timeline
- Load Interconnections
Model Building

System Models
• Load Flow
• Stability
• Short Circuit
• Economic

ITC provides system topology and coordinates with GOs on generator parameters and LSE/DP’s on load parameters.

MISO is responsible for development of the regional models (MOD).
# MISO Data Submission Responsibilities

<table>
<thead>
<tr>
<th>Entity</th>
<th>Responsibility</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Generator Owners</strong></td>
<td>Submit modeling data for their existing and approved future generating facilities. Ensure data is consistent with the topology submitted by their interconnected transmission owner.</td>
</tr>
<tr>
<td><strong>Load Serving Entities</strong></td>
<td>Provide their load forecasts corresponding to developed scenarios. Ensure data is consistent with the topology submitted by their TO.</td>
</tr>
<tr>
<td><strong>Transmission Owners</strong></td>
<td>Submit modeling data for their existing and approved future transmission facilities and inter-area transactions.</td>
</tr>
<tr>
<td><strong>MISO and Transmission Planners</strong></td>
<td>Develop modeling data requirements and reporting procedures.</td>
</tr>
<tr>
<td><strong>MISO as the Planning Coordinator</strong></td>
<td>Submit models for its planning area to the Electric Reliability Organization (ERO) or designee.</td>
</tr>
</tbody>
</table>

For more information, visit [https://www.misoenergy.org/Planning/Models/Pages/MOD-032.aspx](https://www.misoenergy.org/Planning/Models/Pages/MOD-032.aspx)
MOD-032: Data for Power System Modeling and Analysis

- MISO, as the planning authority, has worked with the transmission planners to develop steady-state, dynamics and short circuit modeling data requirements and reporting procedures that can be found on MISO’s website at:


- ITC will work with all stakeholders to support model development

Load Serving Entity and/or Distribution Provider

- MOD-020: Providing Interruptible Demands and DCLM Data
- MOD-031: Demand and Energy Data
NERC Modeling Requirements

Generator Owner

- MOD-025: Verification & Data Reporting of Generator Real & Reactive Power Capability
- MOD-026: Verification of Models & Data for Generator Excitation Control System or Plant Volt/Var Control Functions
- MOD-027: Verification of Models for Turbine/Governor & Load Control or Active Power/Frequency Control Functions

This covers many of the NERC standards that require TO, TP, GO, LSE and TP coordination, however it is not an exhaustive list.
# MISO Modeling Timelines

## MTEP17 Power Flow Model Development Schedule

<table>
<thead>
<tr>
<th>Date</th>
<th>Milestone</th>
</tr>
</thead>
<tbody>
<tr>
<td>08/25/2016</td>
<td>LSE/TO and GO data request sent</td>
</tr>
<tr>
<td>08/3/2016</td>
<td>MOD Pass 1 model posted</td>
</tr>
<tr>
<td>09/12/2016</td>
<td>GO and LSE data due</td>
</tr>
<tr>
<td>09/27/2016</td>
<td>TO data due</td>
</tr>
<tr>
<td>10/01/2016</td>
<td>Topology Pass 2 model posted for review</td>
</tr>
<tr>
<td>12/09/2016</td>
<td>Review Pass 3 model posted for review</td>
</tr>
<tr>
<td>12/01/2016 - 01/31/2017</td>
<td>Model review / updates to MOD</td>
</tr>
<tr>
<td>03/24/2017</td>
<td>Final MTEP models completed / posted</td>
</tr>
<tr>
<td>05/01/2017</td>
<td>Updates to models before sent to MMWG</td>
</tr>
<tr>
<td>06/01/2017</td>
<td>Models submitted to ERAG MMWG</td>
</tr>
</tbody>
</table>

## MTEP17 TSAT Dynamic Model Development Schedule

<table>
<thead>
<tr>
<th>Date</th>
<th>Milestone</th>
</tr>
</thead>
<tbody>
<tr>
<td>03/01/2017</td>
<td>MISO issues dynamics data request</td>
</tr>
<tr>
<td>03/22/2017</td>
<td>Stakeholders complete dynamics updates and send to MISO</td>
</tr>
<tr>
<td>05/08/2017</td>
<td>MISO posts draft TSAT models for review. Stakeholder review starts.</td>
</tr>
<tr>
<td>05/22/2017</td>
<td>Stakeholders comments on draft models due to MISO</td>
</tr>
<tr>
<td>06/14/2017</td>
<td>MISO incorporates changes from draft review</td>
</tr>
<tr>
<td>06/15/2017</td>
<td>MISO posts final TSAT models</td>
</tr>
</tbody>
</table>

https://www.misoenergy.org/Planning/Models/Pages/Models.aspx
TOs & GOs must have a facility rating methodology

- Facility Ratings shall respect the most limiting applicable Equipment Rating on the individual equipment that comprises the Facility

Rating of all joint owned facilities must be coordinated per FAC-008

- Generator tie lines
- Transmission to transmission interconnections
MISO Roles & Responsibilities

ITC
- Registered *Transmission Owner (TO)*, *Transmission Planner (TP)*, and *Transmission Operator (TOP)*
- Develops a long-term (generally one year and beyond) plan for the reliability of the interconnected bulk electric transmission system within its portion of the planning authority area
- Primary responsibility to develop projects and ensure compliance with local planning criteria

MISO
- Registered *Planning Authority (PA)* (among other functions) with functional control of open and transparent planning process
- Coordinates and integrates transmission facilities and service plans, and resource plans from local TOs, TPs, Generator Owners (GO), Load Serving Entities (LSE), Resource Planners (RP) and Distribution Providers (DP)
- Approval of all projects as part of annual plan

Both MISO & ITC are required to perform planning assessments each year per TPL-001
# Planning Timeline

## Typical Annual Planning Activities

<table>
<thead>
<tr>
<th>Year</th>
<th>2016</th>
<th>2017</th>
</tr>
</thead>
<tbody>
<tr>
<td>Month</td>
<td>Jan</td>
<td>Feb</td>
</tr>
<tr>
<td>------</td>
<td>-----</td>
<td>-----</td>
</tr>
<tr>
<td>ITC Model Development</td>
<td></td>
<td></td>
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<tr>
<td>2016 Models</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2017 Models</td>
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<tr>
<td>ITC Planning Assessment</td>
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<tr>
<td>2016 Assessment</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2017 Assessment</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Projects Submitted to MISO MTEP</td>
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<tr>
<td>MTEP 2017</td>
<td></td>
<td></td>
</tr>
<tr>
<td>MTEP 2018</td>
<td></td>
<td></td>
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<tr>
<td>MISO MTEP</td>
<td></td>
<td></td>
</tr>
<tr>
<td>MTEP 2016</td>
<td></td>
<td></td>
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<tr>
<td>MTEP 2017</td>
<td></td>
<td></td>
</tr>
<tr>
<td>MTEP 2018</td>
<td></td>
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</tbody>
</table>
MISO Coordination

Typical Date Deadlines

• Sept 15 – All projects for the following year MTEP must be received, along with justifications and any non-MISO models used for justification

• Nov 5 – Initial stakeholder comments to projects due

• Dec 30 – 1st SPM; Presentation of projects and address all unresolved stakeholder comments

• March 31 – 2nd SPM; Preliminary results of MISO evaluation of submitted projects

• April 15 – Stakeholder comments due for projects intended to move to Appendix A

• June 30 – 3rd SPM; MISO presentation of final MTEP plans and cost eligible projects

ITC is responsible for working with stakeholders to address and resolve comments/issues

MISO brought in if stakeholder concerns can not be resolved
Load Interconnection

Interconnecting customer submits necessary data:

- Load modifications (real & reactive)
- Location
- Desired in-service date

ITC typically requires 60 days to perform planning review (more or less depending on complexity).

Brought to MISO through normal MTEP process if time allows, expedited review if not.
Questions?
New NERC Requirements for Transmission Operators

Vinit Gupta
Director, Operations Engineering
Agenda

• What is changing?
• Real-time assessment review, system operating limits (SOL) and industry update
• Operational planning analysis review
• Operational reliability data specification discussion
New NERC Requirements for TOP

TOP-001-3 requires:
• Each transmission operator (TOP) to perform a real-time assessment (RTA).
• Initiate an operating plan.

TOP-002-4 requires:
• Each TOP to perform operational planning analysis (OPA).
• Have an operating plan for next day operations.

TOP-003-3 requires:
• Each TOP shall maintain a documented data specification for OPA, RTA and real-time monitoring.
NERC defines RTA as:

- Evaluate pre-contingency conditions.
- Evaluate post-contingency conditions.
- Inputs: RTA utilizes inputs such as load, generation levels, breaker status, ratings, protection system degradations etc.
Real-time Assessment (RTA)

RTA Options/Guidelines:

- Real-time tools (SE/RTCA etc.)
- Manual studies
- Third-party service reliance
- Other tools, such as shift factors
RTA - Considerations

• Protection system and phase angle monitoring
• It is both real-time and post contingent
• Back up processes when primary RTA fails
• Evidence you will keep for RTA completion
RTA Results – Actions Required

- NERC requires TOP to identify System Operating Limit (SOL) exceedances and take action
- TOP to communicate and coordinate with RC (MISO)
- MISO protocols allows TOP and MISO to develop coordinated plans
- MISO rules requires time based monitoring of system limits
RTA - Using a Third Party

- Have an agreement in place with third party
- Continuous visibility of RTA results
- Compliance burden still lies with you
- Process when third party fails to perform RTA
- Process when communication with third party is lost
RTA - Industry Developments

• MISO developed operating protocols
• NERC developed compliance guidelines
  – http://www.nerc.com/pa/comp/guidance/Pages/default.aspx (Real Time Assessment (NERC OC) under proposed implementation guidelines)
• NERC third-party guidelines
  – NERC Compliance Public Bulletin #2010-004
• TOPs required to perform a next-day analysis.

• MISO protocols allow TOPs to use MISO analyses, however TOP must review MISO analyses and ensure coordinated plans are created for SOL exceedances.

• TOPs are required to provide operating plans to MISO and notify others if impacted.
• TOP to maintain a documented specification for data needed for RTA, OPA and real-time monitoring
• Data specification should be distributed
• TOP to satisfy the obligations of data specification upon receipt
TOP Responsibilities – Summary

• TOPs are required to have processes in place for RTA, monitoring RTA results and taking action
• The requirements are independent of system size
• Monitoring and tracking SOL exceedances is becoming more complex
• Backup processes are required for these capabilities
• Next-day analysis process required
• TOPs are required to maintain a data specification and respond to data specifications
• Scope of RTA and next day expanded to include Protection system, phase angles, etc.
• Significant coordination, communication and compliance evidence tracking
Questions?
CONNECTING
Energy Infrastructure

Internal Controls
Matthew Di Maggio
Sr. Reliability Assurance Analyst, Reliability Assurance
Objectives

• Overview of Risk and Internal Controls
• The Internal Controls Process
• ITC’s Internal Controls Program
Risk

What is risk?
The possibility of an event occurring that will have an adverse impact of the achievement of objectives (reliability of the Bulk Electric System).

How do we measure risk?
Risk is measured in terms of likelihood and impact.

What is a risk assessment?
The identification, evaluation and estimation of the levels of risks involved in a situation, their comparison against benchmarks or standards, and determination of an acceptable level of risk.
Five Types of Risk

• **Strategic** – risk that would prevent an organization from accomplishing its objectives (meeting its goals).

• **Financial** – risk that could result in a negative financial impact to the organization (waste or loss of assets).

• **Regulatory (Compliance)** – risk that could expose the organization to fines and penalties from a regulatory agency due to non-compliance with laws and regulations.

• **Reputational** – risk that could expose the organization to negative publicity.

• **Operational** – risk that could prevent the organization from operating in the most effective and efficient manner or be disruptive to other operations.
How to Identify Risk

Some questions to ask:

- What could go wrong?
- How could we fail?
- What activities are most complex?
- What activities are regulated?
- On what information do we most rely?
- What assets do we need to protect?
- How could someone or something disrupt our operations?
Objective of a Risk Assessment
- Identify and prioritize the most important or key areas (what really matters)

Measure and prioritize risk exposures
- The higher the risk exposure, the higher the priority

ITC’s Risk Assessment Model
- Scores based on 11 key risk indicators that influence the likelihood of the operational risk event and potential impact
- Risk score used to prioritize control reviews
- Full assessment every 3 years; Annual refresh
Key Operational Risk Indicators

- Routine vs. Non-Routine
- Automation vs. Manual
- Cross-Functional (Internal)
- 3rd Party Interaction (External)
- ERO High Risk Standards
- Significance of Changes in Standard or Process
- Key Personnel Turnover
- NERC VRF
- Reliability and/or Reputational Impact
- Violation History
- Automated Internal Controls
ITCs Risk Assessment Model

• How do we calculate the risk score?
• Rate each of the risk factors on a scale of “1” to “5”
  • “1” indicating lower risk, “5” indicating higher risk
• Weight each factor based upon its significance
• Multiply each factor by its risk weight to calculate an overall score
• Rank each score from high to low
• Focus on the areas with the highest risk score (what really matters)
### Inherent Risk Assessment

|----------|---------|-----------|----------------------|-----------------------------|--------------------------|-------------------------|--------------------------|--------------------------|----------------|------------------|--------------------------|--------------|------------|---------------------|

**Note:** The table above represents a portion of the Inherent Risk Assessment for a specific standard (ITC 2017 Reliability Assurance Risk Assessment). It includes key indicators, factors affecting likelihood, and impact factors, along with risk ratings.
# 2017 ITC’s Inherent Risk Assessment

## Risk Score 3.1 - 3.6

| CIP 008.5 | R2, 3, 5 |
| PRC 025.1 | R1 |
| CIP 002.51a | R2 |
| NUC 001.3 | R3, 6, 8 |
| PRC 006.2 | R10 |
| IRO 017.1 | R2 |
| TOPO 002.4 | R3, 6 |
| COM 007.4 | R2, 4, 6 |
| PRC 008.9 | R2 |
| CIP 000.3 | R2, 3 |
| TOP 000.3 | R1 |
| FAC 000.3 | R3 |

**Risk Score 1.0 - 2.5**

| CIP 008.1 | R3, 2, 4, 5, 6 |
| PRC 025.1 | R1 |
| MOD 029.2a | R1, 2, 3, 4 |
| MOD 008.1 | R1, 2, 3, 4, 5 |
| MOD 004.1 | R6, 8, 9, 10, 11 |
| PRC 001.5 | R3, 4 |

**Risk Score 2.6 - 3.0**

| CIP 008.1 | R3, 2, 4, 5, 6 |
| PRC 025.1 | R1 |
| MOD 029.2a | R1, 2, 3, 4 |
| MOD 008.1 | R1, 2, 3, 4, 5 |
| MOD 004.1 | R6, 8, 9, 10, 11 |
| PRC 001.5 | R3, 4 |

## Risk Score 3.6 - 5.0

| CIP 001.1 | R1, 2, 3, 5 |
| CIP 008.6 | R1 |
| CIP 008.5 | R1 |
| PRC 001.1 | R3, 4, 5 |
| TOP 002.4 | R4, 1 |
| CIP 004.6 | R3, 4, 5 |
| TOP 003.3 | R5, 6 |
| FAC 003.4 | R2, 4, 5, 6, 7 |
| PRC 005.6 | R3, 5 |
| EOP 003.2 | R2, 3 |

| CIP 001.1 | R1, 2, 3, 5 |
| CIP 008.6 | R1 |
| CIP 008.5 | R1 |
| PRC 001.1 | R3, 4, 5 |
| TOP 002.4 | R4, 1 |
| CIP 004.6 | R3, 4, 5 |
| TOP 003.3 | R5, 6 |
| FAC 003.4 | R2, 4, 5, 6, 7 |
| PRC 005.6 | R3, 5 |
| EOP 003.2 | R2, 3 |

## Additional Notes

- **2017 ITC’s Inherent Risk Assessment** provides a framework for evaluating risks associated with various components and scenarios.
- The assessment categorizes risks into score ranges from 1.0 to 5.0, with 3.1 - 3.6 being high-risk scenarios.
- Key components and risk factors are highlighted in the provided table and graphical representation.
What is a control?
An action [taken by you, me, management, the board of directors, and/or other parties] to manage risk and increase the likelihood that established objectives and goals will be achieved.

Controls should be designed to bring about appropriate responses to risks. In other words, controls help to reduce or mitigate risk.

Controls should address the root cause of a risk event, not the symptom(s).
Internal Control Types

Two main control types:

- **Prevent** undesired outcomes
- **Detect** deviations in performance

Internal controls are also of two varieties:

- **Automated** – Systematically with no human intervention
- **Manual** – Requires human intervention
Preventive Controls

Examples:

• Training and Awareness
• Three-Part Communication
• Forward Studies and Day Ahead Studies
• ID badges and door locks
• Operating guides
• Defined testing and/or maintenance program
Detective Controls

Examples:

- Review of logged activity for Control Room
- Review of phone logs for three-part communication
- Review of system access logs
- Management Reviews
- Self Certifications and Audits
- Review of activity and exception reports
Automated Controls

An automated control will prevent improper activities from occurring

Advantages:
- No manual intervention
- Reliable Time-stamp
- Activity is repeatable

Examples:
- Programmed alarms in a system like TMS
- System generated logs
- Password Controls over access into a system
Manual Controls

Least desired

• Can often be circumvented
• Often performed after the fact

Example:
  ➢ User Access Reviews
For an Internal Control to be effective the following should be present:

- The control activity should be assigned to a specific function/individual
- The control activity must be executed in a defined time period (daily, weekly, monthly, yearly)
- The control activity must be repeatable
Internal Control Development

1. Document Process
2. Design Controls
3. Review with SMEs/SOs and get approval
4. Test Design
5. Test Effectiveness
6. Identify and Correct Deficiencies
7. Review and Improve Design
Internal Control Monitoring

Benefits of monitoring the effectiveness of Internal Controls:

- Ensures that there is a sustainable and repeatable process
- Identifies potential improvements to process efficiencies and internal control value
- Provides timely information for improved assessment and management of risk
- Improves the overall value of internal controls towards compliance efforts as they relate to the reliability of the BES
- Ensures that there has been no degradation of the controls over time
- Identification and correction of control deviations and failures
- Elimination of unnecessary or inefficient controls
An Internal Controls calendar has been developed based on:

- Timing of Process/Event
- Frequency of controls

### Internal Controls Planning Calendar -- 2017

<table>
<thead>
<tr>
<th>Process</th>
<th>Actual OATI Evidence Request Execution Date</th>
<th>Primary SME/Evidence Provider</th>
<th>Control/Process Owner (Primary Approver and when required)</th>
<th>Control Reviewer (Secondary Approver)</th>
<th>Stk Owner (Final Approver)</th>
<th>Test Frequency</th>
<th>Timing of Execution</th>
<th>RA Reviewer</th>
</tr>
</thead>
<tbody>
<tr>
<td>Facility Ratings Validation (R6) -- Spotcheck 1 changed circuit per quarter for ITC, ITCMW, ITCGP, METC annually.</td>
<td>1/11/2017</td>
<td>C R. Kloecker</td>
<td>R. Kloecker</td>
<td>C. Capra</td>
<td>Quarterly</td>
<td>Jan, Apr, Jul, Oct</td>
<td>MD</td>
<td></td>
</tr>
<tr>
<td>Facility Ratings Validation (R6) -- Spotcheck 1 un-changed circuit per quarter for ITC, ITCMW, ITCGP, METC annually.</td>
<td>1/11/2017</td>
<td>C R. Kloecker</td>
<td>R. Kloecker</td>
<td>C. Capra</td>
<td>Quarterly</td>
<td>Jan, Apr, Jul, Oct</td>
<td>MD</td>
<td></td>
</tr>
<tr>
<td>GMD - OCR-019 Procedure Review (OCR-019 Geomagnetic Disturbance Operating Procedure)</td>
<td>1/1/2017</td>
<td>C K. Harrison</td>
<td>K. Harrison</td>
<td>V. Gupta</td>
<td>Annual</td>
<td>January</td>
<td>MD</td>
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</tr>
<tr>
<td>GMD - Maintenance of Mailing List</td>
<td>1/1/2017</td>
<td>C K. Harrison</td>
<td>K. Harrison</td>
<td>V. Gupta</td>
<td>Annual</td>
<td>January</td>
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<td>GMD - Reporting &amp; Documentation RC Notification &amp; Details</td>
<td>1/19/2017</td>
<td>C G. Milosek</td>
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<td>D. Vohnik</td>
<td>Semi-annual</td>
<td>Jan, July</td>
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<td>GMD - Monitoring of High Risk Transformers</td>
<td>1/1/2017</td>
<td>C K. Harrison</td>
<td>K. Harrison</td>
<td>V. Gupta</td>
<td>Annual</td>
<td>January</td>
<td>MD</td>
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</tbody>
</table>
OATI – Internal Control Module

- The IC Module is a flexible workflow tool
- The IC module will allow us to record and track controls as they relate to Reliability Requirements
- The IC Module will allow us to show what we have developed
OATI - Internal Control Module

Internal Controls Dashboard
Questions?
Agenda

• Typical voltage profiles in Michigan
• Voltage effects on power quality
• Benefits of controlling voltage
• Improving system voltage
## Default Bus Voltage Limits

<table>
<thead>
<tr>
<th>Nominal kV</th>
<th>Low Limits (kV / pu)</th>
<th>High Limits (kV / pu)</th>
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</thead>
<tbody>
<tr>
<td></td>
<td>Emergency</td>
<td>Normal</td>
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<tr>
<td>120</td>
<td>110.4</td>
<td>116.4</td>
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<tr>
<td>138</td>
<td>127</td>
<td>133.9</td>
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<tr>
<td>230</td>
<td>211.6</td>
<td>223.1</td>
</tr>
<tr>
<td>345</td>
<td>317.4</td>
<td>334.7</td>
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</table>

## Typical Voltage Profile

<table>
<thead>
<tr>
<th>Nominal kV</th>
<th>Typical Low</th>
<th>Typical High</th>
</tr>
</thead>
<tbody>
<tr>
<td>120</td>
<td>121</td>
<td>125</td>
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<td>345</td>
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<td>362</td>
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</tbody>
</table>
Typical Voltage Profile Example

Typical 345 kV Voltages

Date

Voltage (kV)

Normal
High Limit
Normal
Low Limit

Sub 1
Sub 2
Sub 3
Sub 4
How does voltage affect power quality?

• Examples of power quality disturbances:
  • Over-voltages
  • Oscillatory transients
  • Voltage sags / swells
  • Distortion
  • Power frequency variations
  • Interruptions
Voltage Benefits

Why do we control voltage?

- Keeps the energy “pipeline” open
- Helps maintain system reliability
  - Minimizes equipment wear and damage
  - Prevents voltage collapse (blackouts)
  - Promotes the ability to deliver continuous, uninterrupted power
  - Reduces unplanned outages
Interconnections with ITC are required to maintain a voltage schedule for the safety of the grid.

- Generators have a strong effect on system voltage
- Shared responsibility to promote system reliability
- Reduces the likelihood of unplanned outages due to voltage
- Nearby generators have the same voltage schedules to avoid conflicting reactive controls
FERC revised *pro forma* LGIA

- Eliminated the exemptions for non-synchronous generators to provide reactive power
- All newly interconnecting non-synchronous generators can be required to provide net 0 MVAR at 0 MW output applied at the high-side of the substation GSU
- ITC filed comments in support
ITC is continuously striving to improve system voltage.

- New projects to allow better voltage control
- Voltage SME reviews EI Sketches for capacitors, reactors, generators, etc.
- Planning includes operations for reactive power guidelines in new GIAs
Questions?
Introduction

Since 1993, there has been an observed **downward trend for frequency response** in the Eastern Interconnection. It raises concerns that credible contingencies may result in frequency excursions, such as:

- The reduction of system inertia with the retirement of conventional generation resources.
- The continued penetration of renewable energy resources, most of which are electronically coupled to the grid, are presenting new and different technical challenges.
- The continued growth of load management and other demand-side initiatives.

**Taken together**, it is clear that maintaining adequate frequency response for bulk power system reliability is becoming more important and complex.
• In recent years, NERC has undertaken various activities in an effort to understand the steady decline in frequency response, particularly in the Eastern Interconnection.

• In 2010 as part of the 2007-12 Frequency Response Project, NERC launched the Frequency Response Initiative and has since revised and issued standards: BAL-003-1, Frequency Response and Frequency Bias Setting.

• The initiative includes performing in-depth analysis of interconnection-wide frequency response to achieve a better understanding of the factors influencing frequency performance across North America.
NERC Frequency Response Definitions

- **Frequency Response**: The ability of a system or elements of the system to react or respond to a change in system frequency.

- **Frequency Response Obligation**: The balancing authority’s share of the required frequency response needed for the reliable operation of an interconnection.

- **Frequency Response Sharing Group**: A group whose members consist of two or more balancing authorities that collectively maintain, allocate and supply operating resources required to jointly meet the sum of the frequency response obligations of its members.

Supply/Demand Balance

Controls

- Droop
- AVR
- AGC
- Governor
Frequency control can be divided into four overlapping windows of time:

Balancing and frequency control occur over a continuum of time using different resources.
Primary Frequency Control

- **Interconnections**: Actions provided by the interconnection to arrest and stabilize frequency in response to frequency deviations. (Bias)

- **Governor Action**: Governors on generators sense a change in speed and adjust the energy input into the generator’s prime mover. (i.e. Cruise Control)

- **Load**: The speed of motors in an interconnection change in direct proportion to frequency. As frequency drops, motors will turn slower and draw less energy. As frequency increases, motors will turn faster and draw more energy.
Secondary Frequency Control

- **Secondary Control**: Provided by both spinning and non-spinning reserves.

- **Auto Response**: AGC automatically restores frequency to its scheduled value, 60 Hz.

- **Manual Response**: Actions taken by BAs and RSGs to restore system demand/supply balance.

These actions will restore both scheduled frequency and primary frequency response.
Tertiary Frequency Control

- **Tertiary Control**: Encompasses steps taken to restore spinning and non-spinning reserves to handle current and future contingencies.

ACE is back to normal

Normal AGC operations
This includes small offsets to scheduled frequency to keep long-term average frequency at 60 Hz.

Such as:

Time Error Correction
Classic Frequency Excursion Recovery

This is load decrease as a result of generation increase.

BAL-003 Field Test – Interconnections 2014 Candidate Events Profiles Using Frequency Traces for Same One-Second Median
Current Eastern Interc. Frequency Response

No “Point C” to “Point B” Recovery

Response “Withdrawal”
Wind Inertial & Governor Controls

Michigan Footprint Inertial Impact

Retired Steam Turbines
1617 MW

Wind & Solar Combined Cycle
2232 MW

Credit: ITC – System Reliability Specialists
In Summary

• Collectively, it is clear that maintaining adequate frequency response for bulk power system reliability is becoming more important and complex.

• It is important that the power industry understands the growing complexities of frequency control, frequency response, and is ready with comprehensive strategies to stay ahead of any potential problems.

• Sharing the burden. Maintaining as many of our generators on automatic governor controls in order to respond to system disturbances, arrest frequency declines and use their inertial capabilities to assist in post-disturbance frequency recovery.

• As wind generation grows and displaces conventional synchronous generators, using active power management systems with special inertial and governor controls becomes imperative for adequate frequency response and system reliability.
Questions?
Thank You for Attending