Phase II Technical Subgroup Meeting #6
August 24, 2018
(Docket No. 16-521)
<table>
<thead>
<tr>
<th>Time</th>
<th>Topic</th>
</tr>
</thead>
<tbody>
<tr>
<td>9:30 – 9:40</td>
<td>Welcome, Introductions, Overview of Agenda, Expectations, Recap</td>
</tr>
<tr>
<td>9:40 – 10:20</td>
<td>Metering</td>
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<td>- MREA presentation</td>
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<td>- Xcel presentation</td>
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<td>- Metering requirements &amp; Draft TIIR Sec. 8 Discussion</td>
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<tr>
<td>10:20 – 11:50</td>
<td>Interoperability, including communication protocols</td>
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<td>- Xcel presentation</td>
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<td>- IREC presentation</td>
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<td></td>
<td>- Interoperability requirements &amp; Draft TIIR Sec. 9 Discussion</td>
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<tr>
<td>11:50 – 12:10</td>
<td>Cyber security</td>
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<td>12:10-12:20</td>
<td>Meeting Evaluation</td>
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<td>12:20 – 12:30</td>
<td>Next Steps</td>
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</tbody>
</table>
The Commission hereby delegates authority to the Executive Secretary to issue Notice(s), set schedules, and designate comment periods for the scope outlined in paragraphs 2 – 3 below. The Executive Secretary will, in cooperation with the Department of Commerce, convene a work group of appropriate size and composition, and may select a facilitator, to develop the record more fully.

The Commission will transition the Minnesota Interconnection Process to one based on the FERC SGIP and SGIA. The Executive Secretary will set schedules and take comments. It is anticipated that the Commission will consider the record and comments within 18 months of this order, to replace Attachments 1, 3, 4, and 5 to its 2004 Interconnection Standards in this Docket. The Executive Secretary will use the Joint Movants’ May 12, 2016 filing, generally, as the starting point for comments.

In the longer-term (nine to twenty-two months), the Executive Secretary will set schedules and take comments on updating the Minnesota interconnection technical standards. It is anticipated that the Commission will consider the record and comments within 24 months of this Order, to replace Attachment 2 to the Commission’s 2004 Interconnection Standards. This stage of work would incorporate newly revised national technical standards, and other issues identified as areas in need of updating.

The Commission hereby designates Commissioner Matthew Schuerger as lead commissioner pursuant to Minn. Stat. § 216A.03, Subd. 9, with authority to help develop the record necessary for resolution of the issues, and to develop recommendations to the Commission in this docket.
<table>
<thead>
<tr>
<th>Date</th>
<th>Topic</th>
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<tbody>
<tr>
<td>March 23</td>
<td>Scope/Overview; Inventory of Definitions to Discuss</td>
</tr>
<tr>
<td>April 13</td>
<td>Performance Categories; Response in Normal and Abnormal Conditions; MISO Bulk Power System</td>
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<tr>
<td>June 8</td>
<td>Reactive Power and Voltage/Power Control Performance; Protection Requirements</td>
</tr>
<tr>
<td>July 20</td>
<td>Energy Storage; Non-export; Inadvertent export; Limited export, Capacity</td>
</tr>
<tr>
<td>Aug 3</td>
<td>July 20 topics continued</td>
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<tr>
<td>Aug 24</td>
<td>Interoperability (Monitor and Control Criteria); Metering; Cyber security</td>
</tr>
<tr>
<td>Sept 14</td>
<td>Test and Verification; Protocol to witness Testing</td>
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<td>References; Definitions; 1-line diagram requirements; Agreements, Frequency Ride-Through</td>
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<td>Nov 9</td>
<td>Full DGWG Meeting # 7</td>
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</table>
Recap from August 3

• TSG agrees definitions associated with capacity should:
  • follow national standards as closely as possible recognizing timing complications due to the pace of national working groups
  • not re-define a terms defined elsewhere

• Xcel offered a framework for understanding the various terms proposed by TSG re: capacity and export.

• EPRI offered IEEE 1547’s configuration settings as a way to address MN DIP 5.14 language on a limited capacity less than “nameplate rating.”

• TIIR edits of Section 10 should focus on non-export. Limited export may be addressed at a later time.
  • A majority of IREC’s Section 10 edits were related to limited export.

• 7-26-2018 draft TIIR may be updated by stakeholders after this week in a manner that streamlines comments and edits
Goals for TSG #6 on Metering, Interoperability

• Discuss and address draft TIIR language and proposed edits related to Sections 8 Metering & 9 Interoperability.

• Build shared understanding of
  • What the Draft TIIR proposal and TSG edits mean for these sections
  • Detail on metering requirements that should be in the TIIR compared to a utility’s TSM
  • Considerations of statewide uniformity vs. differing utility system requirements regarding interoperability
  • Cyber security responsibilities
• **interconnection system**: The collection of all interconnection and interoperability equipment and functions, taken as a group, used to interconnect a DER to an Area EPS. [24] [IEEE 1547-2018 p. 23 and 7-26-18 Draft TIIR p.16]

• **interoperability**: The capability of two or more networks, systems, devices, applications, or components to externally exchange and readily use information securely and effectively. (IEEE Std 2030®) [IEEE 1547-2018 p. 23 and 7-26-18 Draft TIIR p.16]

• **local DER communication interface**: A local interface capable of communicating to support the information exchange requirements specified in this standard for all applicable functions that are supported in the DER. [IEEE 1547-2018 p. 24 and 7-26-18 Draft TIIR p.16]

  • [24] This term was frequently used in IEEE Std 1547-2003. Given the scope of the present standard, which may have implications to the design of the entirety of the DER, this standard uses the term “DER” in most places.
Draft TIIR Section 8: Metering
Existing Requirements

- Minnesota’s current (adopted 2004) Distributed Generation Interconnection Requirements, specifies the maximum expected metering, monitoring and control requirements.

- Additional metering requirements are found in specific programs or tariffs (e.g. production meters for REC purchases or incentives) and whether the customer or utility pays for the meter and expenses varies.

- Any metering requirements necessitated by the use of the DER shall be installed at the Interconnection Customer’s expense. [MN DIP Section 5.4]

- Who pays is not in scope for the technical requirements

<table>
<thead>
<tr>
<th>Generation System Capacity at Point of Common Coupling</th>
<th>Metering</th>
<th>Generation Remote Monitoring</th>
<th>Generation Remote Control</th>
</tr>
</thead>
<tbody>
<tr>
<td>&lt; 40 kW with all sales to Area EPS</td>
<td>Bi-Directional metering at the point of common coupling</td>
<td>None Required</td>
<td>None Required</td>
</tr>
<tr>
<td>&lt; 40 kW with Sales to a party other than the Area EPS</td>
<td>Recording metering on the Generation System and a separate recording meter on the load</td>
<td>Interconnection Customer supplied direct dial phone line, Area EPS to supply its own monitoring equipment</td>
<td>None Required</td>
</tr>
<tr>
<td>40 – 250 kW with limited parallel</td>
<td>Detented Area EPS Metering at the Point of Common Coupling</td>
<td>None Required</td>
<td>None Required</td>
</tr>
<tr>
<td>40 – 250 kW with extended parallel</td>
<td>Recording metering on the Generation System and a separate recording meter on the load</td>
<td>Interconnection Customer supplied direct dial phone line, Area EPS to supply its own monitoring equipment</td>
<td>None Required</td>
</tr>
<tr>
<td>250 – 1000 kW with limited parallel</td>
<td>Detented Area EPS Metering at the Point of Common Coupling</td>
<td>Interconnection Customer supplied direct dial phone line and monitoring points available, See B (i)</td>
<td>None Required</td>
</tr>
<tr>
<td>250 – 1000 kW With extended parallel operation</td>
<td>Recording metering on the Generation System and a separate recording meter on the load</td>
<td>Required Area EPS remote monitoring system, See B (i)</td>
<td>None Required</td>
</tr>
<tr>
<td>&gt;1000 kW With limited parallel Operation</td>
<td>Detented Area EPS Metering at the Point of Common Coupling</td>
<td>Required Area EPS SCADA monitoring system, See B (i)</td>
<td>None required</td>
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Source: Att 2. Technical Requirements, Sept 28, 2004 Order establishing interconnection standards
NERC Modeling Standards

NERC has transmission standards for the Bulk Electric System that require knowledge of the peak system load without DER netted with the load. Issue is that without a production meter, the ability to identify the “true” peak system load is not feasible.

Most NEM interconnections are not incorporating a production meter unless an incentive program is tied to the need for a production meter.
NERC Modeling Standards

MOD-032-01 : Model Building Standards
Transmission companies are to represent generation type(s) and load profiles at each of transmission interconnection points along with max load, max generation and net loading

MOD-032-1 — Data for Power System Modeling and Analysis

A. Introduction

1. Title: Data for Power System Modeling and Analysis
2. Number: MOD-032-1
3. Purpose: To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.
NERC Modeling Standards

TPL-001-4: Transmission System Planning Performance Requirements
Requirements for planning, stability, contingency and other types of transmission analysis. Basically a stress test analysis for the transmission system.

Many references to system peak load modeled in a dynamic setting. Without the knowledge of how much load is being masked by DER, the true system peak load is not being modeled.

<table>
<thead>
<tr>
<th>Standard TPL-001-4 — Transmission System Planning Performance Requirements</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>A. Introduction</strong></td>
</tr>
<tr>
<td>1. Title: Transmission System Planning Performance Requirements</td>
</tr>
<tr>
<td>2. Number: TPL-001-4</td>
</tr>
<tr>
<td>3. Purpose: Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.</td>
</tr>
</tbody>
</table>
NERC Modeling Standards

Additional modeling guidelines recently released have expanded the modeling inputs for aggregation of DER behind the substation meter, specifically calling out system peak load without DER, total amount of DER generating, and net effect on load with DER.
NERC Modeling Standards

For Transmission Operators, the following information may be needed:

- Accurate distribution load forecasts on an hourly basis at each load bus
- Accurate DER forecasts on an hourly basis at each load bus
- Accurate net load forecasts on an hourly basis at each load bus
- DER sensitivity to changing weather (cloud cover)
- Aggregate nameplate capacity of DERs is forecasted at each load bus for each year during the operational planning horizon
- Potential real-time changes in DER production due to weather, time of day, etc.
- Voltage and frequency ride through capabilities of DER (IEEE 1547 abnormal performance categories assignment)
- Category III DER momentary cessation voltage threshold
- Voltage control capabilities (IEEE 1547 abnormal performance categories assignment)

NERC Technical Brief on Data Collection
Recommendations for Distributed Energy Resources
NERC Modeling Standards

To meet the NERC standards and guidelines production metering will need to become a requirement. On lightly loaded substations (<2 MW) a handful of NEM systems can easily masking 10%+ of the “true” peak load.

Discussion currently occurring on the ability to model “assumed” masked load for extremely small systems (< 10 kW). Not all transmission planners are comfortable with the assumption concept; especially if higher penetration of small DER systems are expected. Also are concerns for future additional transmission modeling requirement.
Example of DER with Production Meter

- Graphic credit: Michael Coddington, NREL
Operational – near-real-time information on the DER operating characteristics can be needed in order to perform certain actions such as reconfiguring a feeder or restoring a feeder after an outage.

Planning – an archive of time-series information over multiple years of DER operation is required for Area EPS and TPS planning.

Regulatory – The Area EPS may have obligations to track and report on the amount of energy produced from renewable energy DER. Specific incentive programs or tariffs can create additional metering needs.

Billing – the Area EPS is responsible for accounting for energy transactions with the DER Operator and shall have access to revenue grade metering information.
Discuss: Draft TIIR Metering Requirements

• How are statewide metering requirements changing with the proposed TIIR language, and why?

• What are the benefits of production meters compared to inverters?
Draft TIIR Section 9: Interoperability
Actors within a smart grid (NIST report)

Source: Updated NIST Smart Grid Framework 3.0
Feb 2014
Current Remote Monitoring and Control Practices

• **Remote monitoring** for all DER at a site that in aggregate is equal or greater than 250 kW in AC nameplate capacity

• Majority of sites use cellular communications to production meter
  – Real power, apparent power, power factor, 3-ph voltage, 3-ph current.

• Some sites require SCADA for operational control or a communication based protection scheme

• Primary objective: Situational awareness for control center and field personnel

Remote Monitoring ≠ Interoperability
What is Interoperability?

• A requirement for a *Local DER Communications* interface which is active and responsive whenever the DER is in the *continuous operating region* or *mandatory operating region*.

• A means of implementing specific DER functionality through standardized information elements as well as monitoring measurements and status information.

**interoperability:** The capability of two or more networks, systems, devices, applications, or components to externally exchange and readily use information securely and effectively. (IEEE Std 2030® [B23])

**local DER communication interface:** A local interface capable of communicating to support the information exchange requirements specified in this standard for all applicable functions that are supported in the DER.
What is in scope of Interoperability?

- Information Exchange
- Information Models
- Protocols

Key for IEEE 1547-2018
- Green: In Scope
- Red: Out of Scope

In Scope: Information Read time requirements of 30 seconds or less

DER Managing Entity
Network Adapter
Network
Local DER Communications Interface
DER or Plant Controller
Application of *Local DER Interface* is at the *Reference Point of Applicability*, which may be the PCC or PoC or, under mutual agreement, a point in-between the PCC and PoC.

**reference point of applicability (RPA):** The location where the interconnection and interoperability performance requirements specified in this standard apply.
What information can be exchanged?

**Nameplate**
- P at unity and specified pf
- S maximum rating
- +/- Q maximum
- Performance Category
  - Normal
  - Abnormal
- Voltage Ratings
- Supported Control Modes
- Make, Model, Version

**Configuration**
- Each rating in the Nameplate Information Table is configurable
- Not intended for continuous dynamic adjustment

**Monitoring**
- Active Power
- Reactive Power
- Voltage
- Frequency
- Operational Status
- Connection Status
- Alarm Status

**Management**
- P and Q control mode settings
- Voltage/frequency trip and momentary cessation parameters
- Enter service after trip parameters
- Cease to energize and trip
- Limit maximum active power

**Draft TIIR:** When information exchange through the *local DER communication interface* is required by the Area EPS, the Area EPS shall have read and write access to all parameters in the nameplate information, configuration information, monitoring information, and management information, as defined by IEEE 1547.
How will information exchange be used in future?

• Real time data to improve power flow and state estimation in Advanced Distribution Management System (ADMS)
  – Information on DER production feeds into ADMS modules that forecast impacts of DER for planned or emergency switching

• DER Monitoring Information for situational awareness (similar to current use)

• DER Nameplate Information available through local DER communications interface provides path for data integrity

• DER Configuration Information is a static means of capacity limiting or modifying other nameplate characteristics

• DER Management Information for remote settings changes
  – Could be on a set schedule (i.e. seasonal) or based on actual conditions (i.e. contingency/emergency)
When is the Local Communication Interface Used?

IEEE 5147-2018, Clause 10.1, Paragraph 3
The decision to use the *local DER communication interface* or to deploy a communication system shall be determined by the Area EPS operator.

Draft TIIR
- “Per IEEE 1547 Section 10.1, the decision to use the *local DER communication interface* or to deploy a communications network is determined by the Area EPS.”
- Use of the *local DER communication interface* can be a complex decision dependent on the DER size and other factors such as penetration and Area EPS characteristics in the area.
- Process for determining use of *local DER communication interface* shall be outlined in the Area EPS Operators’ TSM.
- The DER Operator may be responsible for furnishing the communication channel
- Additional details of the channel and interface shall be in the Area EPS Operators’ TSM
## Interoperability Protocol Options

<table>
<thead>
<tr>
<th>Protocol</th>
<th>Application Layer</th>
<th>Transport Layer</th>
<th>Physical Layer</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>IEEE 1815 (DNP3)</strong></td>
<td></td>
<td>TCP/IP</td>
<td>Ethernet</td>
</tr>
<tr>
<td><strong>IEEE 2030.5 (SEP2)</strong></td>
<td></td>
<td>TCP/IP</td>
<td>Ethernet</td>
</tr>
<tr>
<td><strong>SunSpec Modbus</strong></td>
<td></td>
<td>TCP/IP</td>
<td>Ethernet</td>
</tr>
</tbody>
</table>

- **Physical Layer**: Ethernet
- **Transport Layer**: TCP/IP
- **Application Layer**: Interoperability Protocol Options

- **IEEE 1815 (DNP3)**: Ethernet
- **IEEE 2030.5 (SEP2)**: Ethernet
- **SunSpec Modbus**: Ethernet, RS-485
• **Present:** Xcel Energy uses DNP3 for distribution field devices and communication to meters for DER remote monitoring
  - The other protocols are not currently in use at the distribution level.
  - Modbus is used within substations for communication between devices, but it is not SunSpec Modbus

• **Future:** We are evaluating the protocol options available in IEEE 1547-2018 to determine which will be implemented.
  - It is possible that different protocols will be used for different use cases based on the strengths and weaknesses of each protocol
    • Security features for a given application
  - Protocol translators are an option at the network adaptor interface
Industry Application of Communication Protocols

- **SunSpec Modbus** is the protocol supported now by most manufacturers
  - Historically ModBus was already internal to inverters

- Storage systems alignment around **DNP3** mapping
  - Largely driven by the open standards efforts for energy storage initiated by Modular Energy Storage Architecture (MESA)

- Rule 21 implementation results in **IEEE 2030.5** use between aggregators and utilities
Selecting a Single Protocol for Minnesota?

- **Upside:** The *simplicity* leads to better chances of success with implementing true interoperability and effective information exchange between all applicable DER and Area EPS Operators in the state.
  - Potential to streamline integration for Developers, Installers, and Area EPS Operators

- **Downside:** The *timing* of the MN update means that market forces have not begun to converge on one of the protocols
  - The IEEE 1547 working group had anticipated some consolidation over time.
  - Expectation is that many manufacturers will offer just one of the three protocols. This aligns with standard requirements

Working hypothesis: Standardizing under a single protocol may be practical in the longer term, and assists in effective interoperability, but we need to better understand vendors offerings and back-end system integrations for all affected parties before making this a statewide requirement.
Information Model Usage – IEC 61850

• **Present:** We do not currently use the implementation of 61850-7-420 for information exchange with DER.
  – Historically standard functions were not defined or available through a standard interface for certified equipment
  – Cellular communication with DNP3 protocol to production meter
  – Xcel’s ADMS implementation of common information models is based on IEC 61850

• **Future:** The CIM from IEC 61850-7-420 is encoded in each of the protocols accepted by IEEE 1547-2018.
  – From the field device side, it will be used when future revised UL 1741 leads to compliant equipment
• California, via the Smart Inverter Working Group
  • Selected IEEE 2030.5 as the communication protocol and information model
  • Requires capability by (May 22, 2018) plus 9 months

• Hawaii is currently in discussions about communication models under Rule 14
  • Advanced Inverter Function Working Group hosted a webinar on 8/9 as part of their working group process as an educational meeting

• MISO stakeholder process on DER integration as related to 1547-2018 is just getting started
Communications

Brian Lydic
Regulatory Engineer
IREC
Communications Req’s Concepts

Basic Principles/Assumptions

● Different utilities will have different capabilities/infrastructure
● Hugely different costs can be incurred (by both utility and customer)
● Ubiquitous comms/control of DERs (large and small) is likely years away
● Actual TIIR requirements could vary based on utility capabilities/infrastructure – need to discuss (IREC proposal is dependent on MN utilities’ capabilities and future plans)
● Develop requirements for a “comms port” that can be widely applicable to all DER once utility infrastructure can support it
● Use “traditional telemetry” today for larger systems
● Consider cost cap for traditional telemetry due to varying costs
Comms Port Requirement

- Balance availability of monitoring and control with initial equipment cost (will it be used?)
- Could create penetration limit at which comms port equipment would be required – this allows evolution of each utility individually
- No requirement for comms port equipment at DER when utility is below penetration limit (and no retroactive requirement to add one)
- Future use of comms port and control may need further customer agreements/protections – note difference between equipment availability and agreement to utilize in TIIR
- Develop agreements at future time – should have a few years for market and equipment to develop in response to 1547 req’s
- Requirement should be 1547-based
- Can require DER to accept comms/control in utility’s preferred language, as long as it is one of the three 1547 options (translators may be used, e.g. 2030.5 to SunSpec)
Example to help design Cost Cap

- The below is not a proposal, but an example under consideration in CA
  - CA IOUs have noted that traditional telemetry/communications could likely be provided for $20,000 or less per DER
  - Whether this could/should apply at 250 kW or 1 MW is contested
  - (many details apply)
Discuss: is it in the best interest of MN to allow all combinations allowed by 1547-2018?

- Do organizations have rough order of magnitude cost and schedule estimates for changing from one protocol to a different one from their software architects?

- What will serve MN the best?
  - What will the impact be with regards to test and verification?
What will it take to properly safeguard and utilize smart inverters?

• Training beyond electrical expertise throughout the supply chain including engineers, installers and inspectors

• Updates to 1547.1 and associated standards, including UL 1741

• Certification by NRTLs in accordance with updated standards
Draft TIIR Section 9D: Cyber Security
• Cyber security is a system-wide issue requiring a system-wide solution.

• This standard specifies the base functionality of a DER including the capability of exchanging specific information over a local DER communication interface.

• This standard cannot correctly address system level issues and should not constrain reasonable system solutions.

• The organization responsible for maintaining the reliability and security of the communications path to the DER must also be able to perform regular maintenance, upgrades, and changes to the network components, including the protocol and cyber security mechanisms.
Recent reporting rule-making will impact some stakeholders directly, others indirectly

- Under the current Critical Infrastructure Protection Reliability Standard CIP-008-5 (Cyber Security – Incident Reporting and Response Planning), incidents must be reported only if they have compromised or disrupted one or more reliability tasks.

- The final FERC rule dated July 19 directs NERC to modify the Standard within 6 months to expand the current reporting requirement, including
  - Reporting cyber security incidents that compromise, or attempt to compromise
  - Cyber Security Incident Reporting Reliability Standards; 164 FERC ¶ 61,033
    - Docket No. RM18-2-000; Order No. 848

- We include this for stakeholder awareness throughout the DER supply chain
**Cyber Security in TIIR**

Effective cyber security requires a system-wide solution.

**Examples**
- Network segmentation
- Intrusion detection systems
- Inline blocking devices
- Selective encryption
- Multi-Factor Authentication
- Patching
- Port security
- Strong user names and passwords
- Role based access

TIIR specifies that physical and network security requirements are in scope for Area EPS Operator TSM.
Cyber Security in TIIR

• TIIR leaves requirements to TSM for some of the same reasons as 1547-2018: scope and complexity, system architecture flexibility, and testability
  – Standards should be used where available and applicable

• Recognizes a few areas of focus for Area EPS Operator’s TSM based on Annex D of IEEE 1547-2018
  – DER Physical and front panel security
    • Ex) access to settings or controls
  – DER network security
    • Ex) if communication is required, a firewall or other network security device may be required
  – Local DER communication interface
    • Ex) includes considerations that are applicable to the end-to-end network, such as system architecture

• Implementation of TIIR Section 9D will be a progression that is anticipated to track with device and network security practices being implemented for other advanced field devices
<table>
<thead>
<tr>
<th>Date</th>
<th>Event details</th>
</tr>
</thead>
<tbody>
<tr>
<td>Aug 23</td>
<td>Sept 14 TSG Mtg #7 Draft Agenda and Prep Work Assignment from Staff to TSG</td>
</tr>
<tr>
<td>Sept 5</td>
<td>Prep work due for Sept 14 TSG meeting #7</td>
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Thank You!
See next slide for graphical representation of what IEEE 1547 allows for interoperability in a given use case
This is not a comprehensive list; it is provided in the event you need a place to start looking at cyber security


- Guidelines for Smart Grid Cybersecurity Volume 1 - Smart Grid Cybersecurity Strategy, Architecture, and High-Level Requirements http://dx.doi.org/10.6028/NIST.IR.7628r1

These topics have been proposed as in scope. Bold have been flagged for discussion.

1. Scope/Overview
2. References
3. Definitions
4. Performance Category Assignments
5. Reactive Power Capability and Voltage/Power Control (volt-var & volt-watt) Performance
6. Response to Abnormal Conditions (Ride-through)
7. Protection Requirements
8. Metering
9. Interoperability (Monitoring, Control, Info Exchange, Cyber security)
10. Energy Storage
11. Non-Export; Inadvertent Export
12. Test and Verification Requirements
13. Agreements
14. Consumer Protection (IREC)
15. Reporting (IREC) (Source: “Regulated Utilities” TIIR Draft Proposal)
Discussion: Scope for Statewide Technical Requirements

1. Process requirements
2. Cost allocation
3. Interconnection to transmission system
4. Protection system details of Area EPS or DER
5. Requirements or specification of system impact or facilities studies
6. Application of real and reactive power control functions
7. Details of communication networks; including architecture, technology and protocols, or other specifications related to interoperability
8. Details of metering requirements or specifications
9. Planning or operational considerations associated with Affected Systems, Regional Transmission Operator or Transmission Owners
10. Intentional Area EPS islanding

These topics have been proposed as out of scope by some participants. Bold are flagged for additional discussion.

(Source: TIIR Draft Proposal, p. 9)