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T-D Coordination to Support Reliable Performance of BPS with DER Integration

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Objectives

The objectives of this presentation are to discuss:

Visibility/Data needs

Identify the visibility and other data requirements for effective transmission-distribution (T-D) coordination to support the Bulk Power System (BPS)* situational awareness and reliability.

Functions/Standards

Describe how the data is used to follow standards governing BPS operation and to perform IESO's key functions based on NERC's reliability functional model.

Impacts of DER

Highlight impacts of Distributed Energy Resources (DER) integration and participation in the wholesale market (WSM) on BPS operation and IESO's functions.

* In this presentation the term BPS is used to represent the transmission system (i.e. system "upstream" of T-D interface).

Key Aims of T-D Coordination to Support BPS Reliability

In operation timeframe, to provide information on:

- Planned and forced outages affecting the DER/A*, including the distribution system outages
- Distribution-level services that are scheduled for DER/A operations by an LDC/DSO
- Market offers for dispatchable DER/A in certain format by the certain time (market mechanism)
- Real-time DERs status, MW/Mvar and voltage (telemetry requirements for market participation)

Prior to operation timeframe, to provide information on:

- Installed and projected DER data: location, type, size, modeling configurations, relevant requirements in interconnection agreements, and disturbance response characteristics

* DER/A: individual DERs and DERAs (DER Aggregation)

Agenda

The presentation has three sections:

- Overview of BPS reliability and situational awareness concept and requirements
- NERC functional model and reliability standards highlights
- T-D coordination needs to support BPS reliability

Overview of BPS reliability and situational awareness

Reliability Definitions*

- Reliability can be broken down into two concepts:

1. Adequacy

The **ability** of the electricity system **to supply** the aggregate electrical **demand** and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled **outages** of system elements.

2. Security**

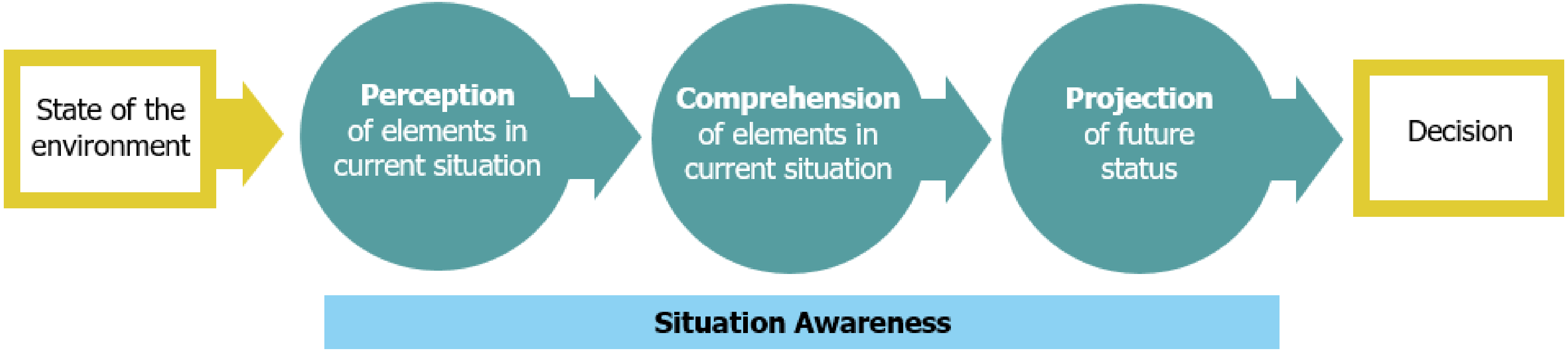
The ability of the bulk-power system to **withstand sudden disturbances**, such as electric short circuits or the unanticipated loss of system elements from **credible contingencies**, while avoiding uncontrolled cascading blackouts or damage to equipment.

* Definitions are verbatim from NERC document Reliability Terminology

** NERC also uses the term "operational reliability" for "security" as shown on this slide

Situational Awareness

- The BPS operates in a dynamic environment with physical properties that constantly change.
- Situational awareness is necessary to maintain reliability, anticipate events and respond appropriately when or before they occur.



Slide based on NERC document Situational Awareness for the System Operator
Diagram adapted from book: Designing for Situational Awareness: An Approach to User-Centered Design

Key Requirements of BPS Reliable Operation

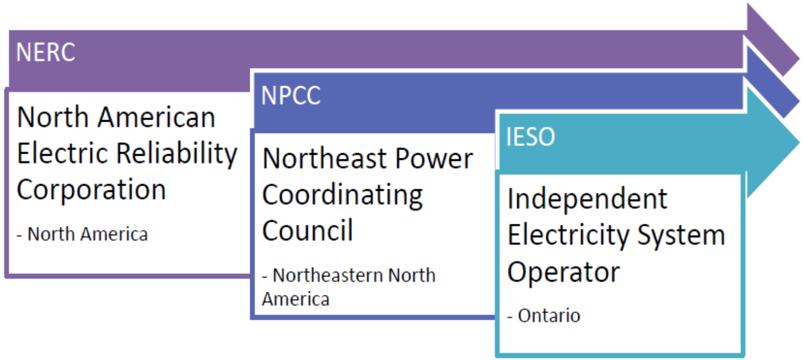
Reliably operating the BPS requires several activities:

- Monitor and estimate availability and state of BPS components (e.g. generation and transmission elements)
- Respect BPS equipment ratings and system operating limits in order to be prepared for credible contingencies
- Maintain the balance between supply and demand by
  - Forecasting the short-term load magnitude and behavior accurately
  - Maintaining adequate quantity of dispatchable resources for essential reliability services
  - Forming a resource dispatch plan for the operation timeframe

NERC functional model and reliability standards

Standards Governing BPS Performance

- BPS planning and operation must adhere to the reliability standards and criteria developed and enforced by NERC, NPCC, and IESO.
- The standards aim to address reliability needs of the interconnected electricity system.
- NERC functional model provides the framework for the development and applicability of NERC's reliability standards.



NERC Reliability Functional Model - version 5.1

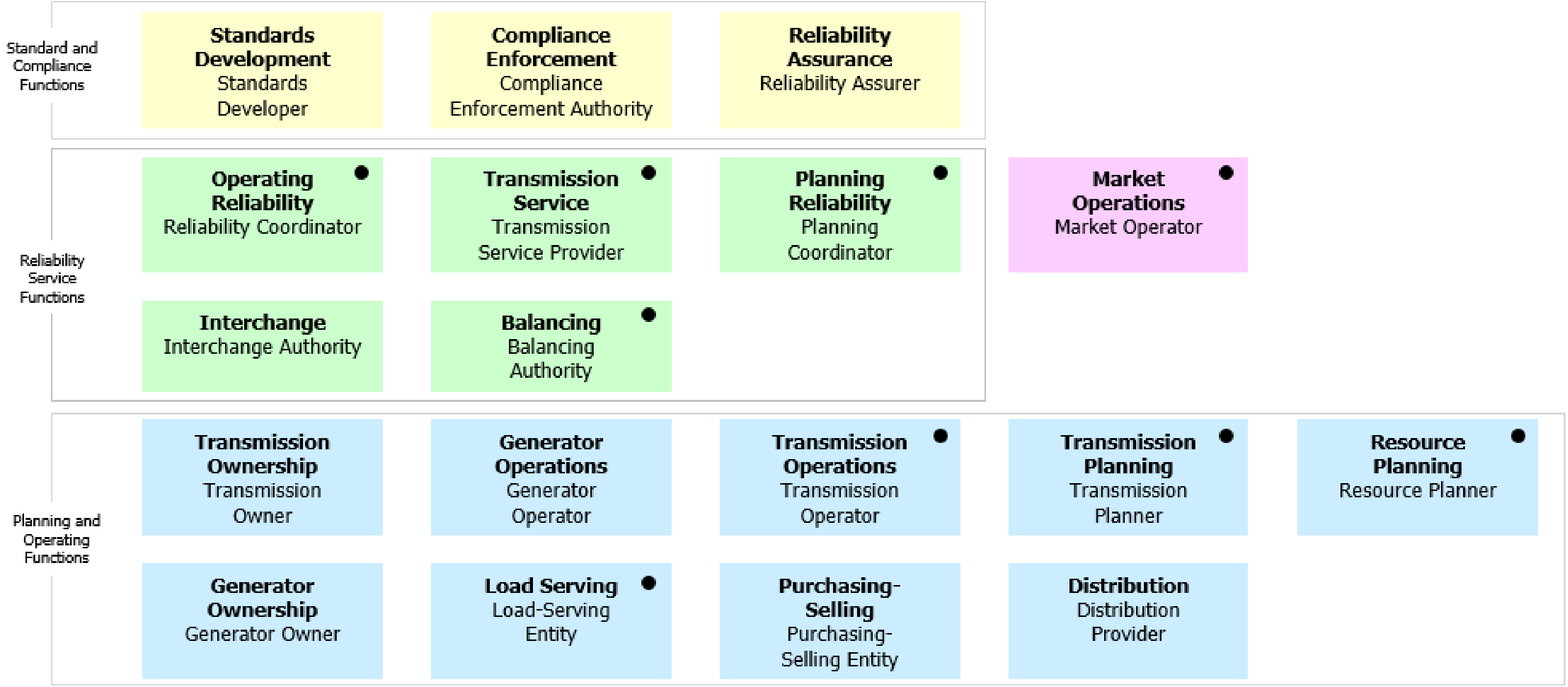


Diagram is recreated from [Reliability Functional Model]

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IESO’s Functional Roles

- The following slides will *very briefly* note the IESO’s roles as:
  - Planning Coordinator (PC)
  - Transmission Planner (TP)
  - Resource Planner (RP)
  - Transmission System Provider (TSP)
  - Load Serving Entity (LSE)
  - Reliability Coordinator (RC)
  - Balancing Authority (BA)
  - Transmission Operator (TOP)
  - Market Operator (MO)

IESO as PC, TP, and RP

- **Planning Coordinator:** Coordinates transmission facilities, service plans, resource plans and protection systems to ensure long-term system reliability.
- **Transmission Planner**: Develops long-term plan for reliability of interconnected bulk electric transmission systems.
- **Resource Planner**: Develops a long-term plan (generally one year and beyond) for resource adequacy of specific loads within a planning authority area.

IESO as TSP, and LSE

- **Transmission Service Provider:** Manages transmission tariffs and provides transmission services.
- **Load Serving Entity:** Secures energy and transmission service to serve electrical demand and energy needs of end-use customers.

IESO as Reliability Coordinator

- Reliability coordinator is the highest level of authority who ensures the reliable operation of the bulk electric system.
- With a wide area view and necessary operational tools, it prevents or mitigates emergency situations.
- Directs Balancing Authorities and Transmission Operators, to ensure the generation-demand balance and operation within interconnection operating reliability limits.
- Coordinates and communicates with other functional entities in its both ahead of time and real-time functions about limitations, operational data, dispatch adjustments, maintenance plans, reliability analyses, corrective actions and emergency procedures, etc.

IESO as Balancing Authority

- The Balancing Authority maintains *load-interchange-generation balance* within an area and supports interconnection frequency in real-time, including:

- **Ahead of Time Activities:** Coordinates operational plans and load forecasts, acquires reliability-related services and implements generator dispatch schedules.

- **Real-time Activities:** Coordinates use of controllable loads, receives real-time operating information and directs resources to maintain balance (dispatch).

- **After the hour Activities:** Confirms implemented interchange.

IESO as Transmission Operator [1/2]

- The Transmission Operator is responsible for
  - The reliability of its *local transmission system* and operates or directs the operations of the transmission facilities, and
  - *Real-time situational awareness* of the transmission system and *responses to contingencies*;
- The Transmission Operator conducts off-line power flow and dynamic studies to calculate transfer capabilities and system operating limits* for different outages, and load scenarios.
- The function involves a number of roles, including ahead of time roles and real-time roles.

*Based on facility information and models provided by Transmission Owners and Generator Owners

IESO as Transmission Operator [2/2]

- **Ahead of Time Roles:**
  - Arranges for reliability-related services from GOs*
  - Develops contingency plans and monitors operation of transmission facilities
  - Coordinates restoration plans with relevant entities
  - Receives maintenance requirements and construction plans and schedules from TO*/GOs

- **Real-Time Roles:**
  - Notifies GOs of transmission system problems such as voltage limitations or overload
  - Deploys reactive resources from TOs and GOs to maintain acceptable voltage profiles
  - Coordinates load shedding with RC and directs Distribution Providers (DP) to shed load if necessary

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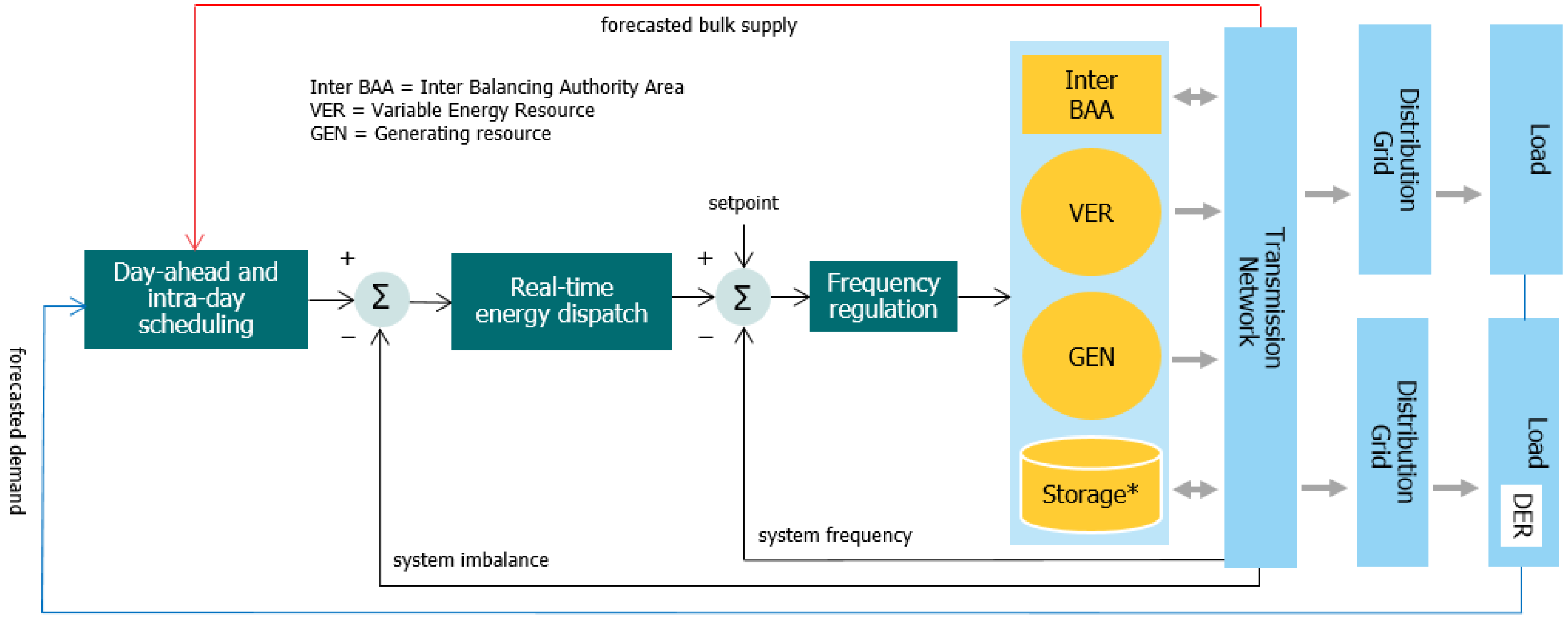
*GO: Generator Owner, TO: Transmission Owner

IESO as Market Operator

- The market operator is the entity that is the interface point of reliability functions with commercial functions.
  - It oversees and runs the wholesale markets by establishing a resource dispatch plan to meet the load forecast (i.e. for the next 5-minute dispatch cycle, and for the next 24 hours).
  - It ensures fair competition of all market participants while ensuring the reliability of the electrical system.
- Market mechanisms can serve as the means to ensure the compliance of market participants with reliability standards.
- Market mechanisms and grid control systems are extensively coupled in a joint market-control system that supports the reliable performance of BPS.

Basic Bulk System Control

Diagram adapted from: JD Taft, Grid Architecture 2, Pacific Northwest National Laboratory (PNNL), 2016



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*all storage resources (e.g. battery storage systems, flywheels, compressed air, etc.)

NERC Reliability Standards

- NERC reliability standards specify planning and operating requirements of Bulk Electric System (BES)* in a number of functional areas listed in the table below.
- Historically, NERC standards are not applicable to distribution system components unless they have direct impact on BES reliable performance (i.e. load shedding or system restoration).

Code	Function
BAL	Resource and Demand Balancing
COM	Communications
CIP	Critical Infrastructure Protection
EOP	Emergency Preparedness and Operations
FAC	Facilities Design, Connections, and Maintenance
INT	Interchange Scheduling and Coordination
IRO	Interconnection Reliability Operations and Coordination

Code	Function
MOD	Modeling, Data, and Analysis
NUC	Nuclear
PER	Personnel Performance, Training, and Qualifications
PRC	Protection and Control
TOP	Transmission Operations
TPL	Transmission Planning
VAR	Voltage and Reactive

*NERC definition: "All transmission elements operated at 100 kV or higher and real power and reactive power resources connected at 100 kV or higher."

Some NERC Standards Impacted by DERs [1/2]

- Standards impacted by DERs penetration are under review to include DPs* and DERs.

Standard	High level description
MOD-032-1	BA/GO/PC/RP/TO/TP/TSP, mechanism to collect necessary modeling data for reliability analysis.
TPL-001-5	PC/TP, transmission system planning performance requirements for a reliable operation of BES over a broad spectrum of system conditions and following a wide range of probable contingencies.
TOP-003-5	TOP/BA, to ensure the availability of data needed to fulfill operational and planning responsibilities.
FAC-001-4	TO/GO, to avoid adverse impacts on the reliability of the BES, TOs and applicable GOs must document and make facility interconnection requirements available so that entities seeking to interconnect will have the necessary information.
FAC-002-4	PC/TP/TO/DP/GO, to study the impact of interconnecting new or changed facilities on the BES.
MOD-031-2	PC/TP/BA/RP/DP, to provide authority for applicable entities to collect demand, energy and related data to support reliability studies and assessments.

*DP: Distribution Provider

Some NERC Standards Impacted by DERs* [2/2]

Standard	High level description
PRC-006-5	PC/TO/DP/UFLS related entities, to establish requirements for automatic UFLS programs as the last resort system preservation measures for frequency control.
IRO-010-4	RC/BA/GO/GOP/TOP/TO/DP, to prevent instability, uncontrolled separation, or cascading outages that adversely impact reliability, by ensuring the RC has the data to monitor and assess its system operation.
IRO-017-1	RC/TOP/BA/PC/TP, to ensure that outages are properly coordinated in the operations planning and near-term transmission planning horizons
TOP-001-6	BA/TOP/GO/DP, to prevent instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the interconnection by ensuring prompt action to prevent or mitigate such occurrences.
TOP-002-4	TOP/BA, to ensure that TOPs and BAs have plans for operating within specified limits.
TOP-010-1(i)	TOP/BA, to establish requirements for real-time monitoring and analysis capabilities to support reliable system operations.

*Reference: NERC SPIDERWG

T-D coordination needs to support BPS reliability

T-D Coordination to Address Reliability Requirements

- The next 6 slides will discuss the need for T-D coordination for different requirements:

  A. Situational awareness

  B. Outage coordination (planned/forced)

  C. Balancing and forecasting

  D. Dynamic/load flow modeling

  E. Contingency definitions and analysis

  F. Wholesale market and service stacking

A. Situational Awareness and Real-Time Operation Needs

- State estimation accuracy in BPS operation depends on accurate monitoring and forecasting (i.e. situational awareness).
- DERs can have a significant effect on the state estimation at each system node (i.e. T-D interface) by altering the net active and reactive power withdrawals/injections.
- In real-time operation, the BPS control room needs to:
  - monitor market-participating DER/A operation to verify if they meet the dispatch targets, and
  - maintain the ability to contact/direct the DER/A in case of emergency.

To address

- Require details on DER/A (i.e. capacity, location, type) to enhance observability at each node.
- Integrate real-time telemetry of DER/A into SCADA* (i.e. MW, Mvar, voltage and status).
- Require timely notice of changes in characteristics and availability of DER/A.

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* Supervisory Control and Data Acquisition

B. Outage Coordination (Planned/Forced)

- Increasing DER penetration adds variability and uncertainty to system operations, requiring more effective coordination to find safe schedule for planned outages.
- In addition to DERs' internal outages, distribution system planned/forced outages can also prevent DERs from meeting DAM* schedules and RTM* dispatch instructions.
- Outage information serves as crucial input for adequacy and security assessment during the operational planning time-frame as well as real-time operational activities.

To address

- Implement an effective T-D coordination protocol among IESO, LDC/DSO*, and DER/A for visibility on limitations and outages of distribution system and DERs, impacting DER/A availability.
- Layout communication steps/reporting requirements for planned/unplanned abnormal operating conditions to provide time and duration of DER/A outages.

*DAM: Day-Ahead Market, RTM: Real-Time Market, LDC: Local distribution Company, DSO: Distribution System Operator

C. Balancing and Forecasting

- If DERs' production is not effectively monitored/estimated, they can "mask" the gross load seen by the Balancing Authority, leading to operational variability and uncertainty.
- DERs displace BPS-connected generation, reducing availability of resources to provide reliability services (e.g. frequency and voltage regulation).
- Maintaining adequate amount of resource, operating reserve and ramping capability requires knowledge of DERs output and operational characteristics.

To address

- Enable participation of dispatchable DERs in WSM*, capturing DERs operational features in IESO tools and processes for balancing and forecasting.
- As part of T-D coordination, receive information on 1) DERs' scheduled distribution-level services and 2) any material changes in operation of other DERs.

*WSM: Wholesale Market

D. Dynamic/Load Flow Model

- DERs' active and reactive power withdrawals/injections and their response to disturbances impact system modeling at the T-D interface (dynamic load model and short-circuit level).
- An accurate representation of DER/A in system security studies in planning, operation and real-time analysis, requires information on location, type, operational settings, and magnitude of DERs.
- Inverter-based DERs penetration impacts BPS operation in terms of power quality, voltage control, inertia/frequency response and short-circuit levels.

To address

- Collect DERs data for reliable modeling and validation. NERC's DER working group* recommends:

1. As much as practical, there should be no threshold for data gathering (i.e. 0 MVA)
2. Represent DERs with modular approach at the T-D interface as aggregated/equivalent resources
3. Model DERs separate from the load

*System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG)

E. Contingency Definition and Analysis

- DERs may be lost during or following a transmission disturbance, exacerbating consequence of certain contingencies (depending on DERs' ride-through and trip settings).
- The disconnection of DERs may be due to distribution network protection scheme settings or DERs' control system response.

To address

- Provide data required to model DER/A at the T-D interface to assess their response to transmission level contingencies and include large-scale DERs in contingency definitions.
- Have a plan to periodically test and validate DER models to reflect their accurate behaviour.
- Coordinate with distribution providers in the connection assessment phase of DERs to implement ride-through requirements based on the market rules and distribution system needs.

F. Wholesale Market Participation and Service Stacking

- Forming a resource dispatch plan is essential for reliability (achieved by market mechanisms).
- DAM and RTM participation are required to be eligible in certain programs/procurements.
- DER/A participation in WSM can provide more controllability in BPS operation and more flexibility in WSM.
- Availability of DER/A in WSM is impacted by providing distribution level services.

To address

- Enable DER/A participation in WSM (i.e. following MRP* and MVDP* requirements) to capture them in DAM and RTM schedule and dispatch plans.
- Require visibility into planned/scheduled distribution-level use of DER/A to enable DER/A to provide “stacked” services (i.e. distribution-level *and* WSM services).
- Require immediate notification in the event of any deviation from DER/A offer.

*MRP: Market Renewal Program; MVDP: Market Vision and Design Program

Key Takeaways

- With high penetration of DERs into the grid, lack of observability, decentralization of resources and displacement of resources providing essential reliability services pose significant challenges to IESO's role as Reliability Coordinator, Balancing Authority and Transmission Operator.
- The effort to facilitate participation of DERs and DER aggregators in wholesale market aims to enable the potential of DERs in providing different services while ensuring reliable operation of BPS using market mechanism.
- To handle vast DER/A integration/participation, an effective T-D coordination protocol is necessary to support situational awareness in BPS operation timeframe (while active distribution system management will also be required).

Key Aims of T-D Coordination

In operation timeframe, to provide information on:

- Planned and forced outages affecting the DER/A, including the distribution system outages
- Distribution-level services that are scheduled for DER/A operations by an LDC/DSO
- Market offers for dispatchable DER/A in certain format by the certain time (market mechanism)
- Real-time DERs status, MW/Mvar and voltage (telemetry requirements for market participation)

Prior to operation timeframe, to provide information on:

- Installed and projected DER data: location, type, size, modeling configurations, relevant requirements in interconnection agreements, and disturbance response characteristics

Next Steps

- T-D coordination considerations to support distribution system reliability will be presented in the following TDWG session.
- Integrate T-D coordination requirements discussed in this presentation in the draft report that is to be developed by the IESO as part of TDWG Deliverable A – Coordination Protocols
- Further investigate requirements for T-D coordination as part of all other TDWG deliverables and capture any needed updates in the draft report for Deliverable A – Coordination Protocols

Thank You

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