Generation Initial Training Program

System Restoration

PJM State & Member Training Dept.

Objectives

Students will be able to:

- Identify the different causes of some of the major blackouts that have occurred
- Identify the effects significant blackouts have on society
- Describe the process and requirements associated with Black Start Generation resources
- Identify the process and requirements for operating during system restoration conditions

History of Blackouts

Great Northeast Blackout: November 9, 1965

- A single transmission line from Niagara generating station tripped due to faulty relay setting
- Within 2.5 seconds, five other transmission lines became overloaded and tripped, isolating 1,800 MW of generation at Niagara Station
  - Generation then became unstable and tripped
- Northeast became unstable and separated into islands within 4 seconds
- Outages and islanding occurred throughout New York, Ontario, most of New England and parts of New Jersey and Pennsylvania

History of Blackouts

WABC Audio

Great Northeast Blackout: November 9, 1965

- Most islands went black within 5 minutes due to generation/load imbalance
- Left 30 million people and 80,000 square miles without power for as long as 13 hours
- Estimated economic losses of over $100,000,000
- Led to the formation of Northeast Power Coordinating Council (NPCC) in 1966 and North American Electric Reliability Council (NERC) in 1968
- Cause: Human error of setting a protective relay incorrectly

History of Blackouts

Great Northeast Blackout

November 9, 1965

History of Blackouts

PJM Blackout: June 5, 1967

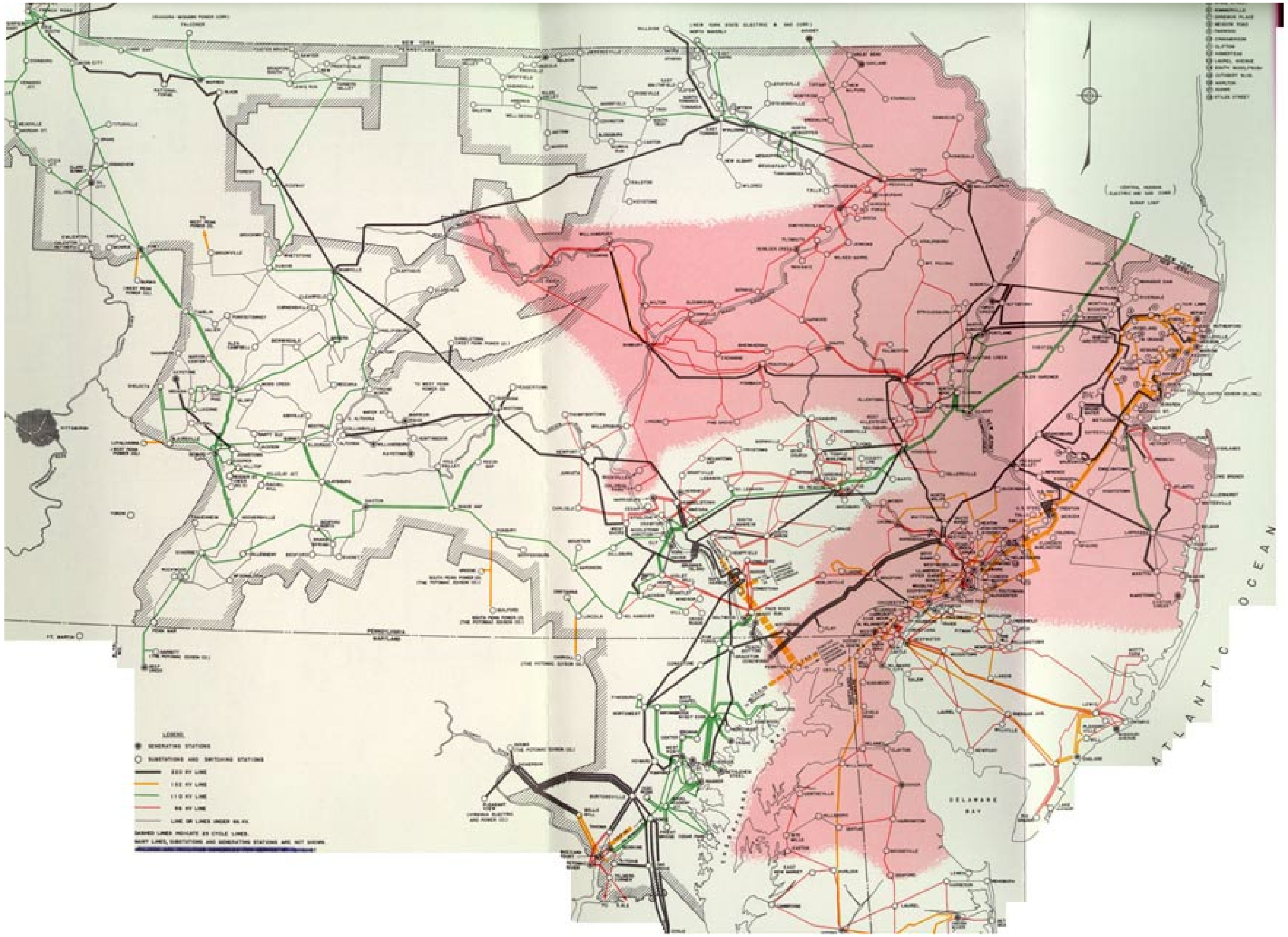
- 3 major system improvements had been delayed beyond the beginning of the summer
  - Oyster Creek nuclear station
  - Keystone #1 unit
  - Keystone 500 kV transmission
- Loss of Nottingham-Plymouth line and Muddy Run Generation
  - Conductor sag
  - First time 4 MR units operated at the same time
- Loss of Brunner Island #2 - Heavy loads and low voltages

History of Blackouts

PJM Blackout: June 5, 1967

- Loss of S. Reading-Hosensack, Brunner Island #1 Unit
- Cascading trippings of transmission resulted in system separation
- Load in affected area exceeded the scheduled operating capacity by more than 700 MW
- System stabilized at 53 Hertz
- Load shedding may have saved the island
  - No under-frequency load shedding was installed at the time
- All protective relaying worked properly
- Led to more extensive voltage monitoring and UPS for instrumentation and control

History of Blackouts



History of Blackouts

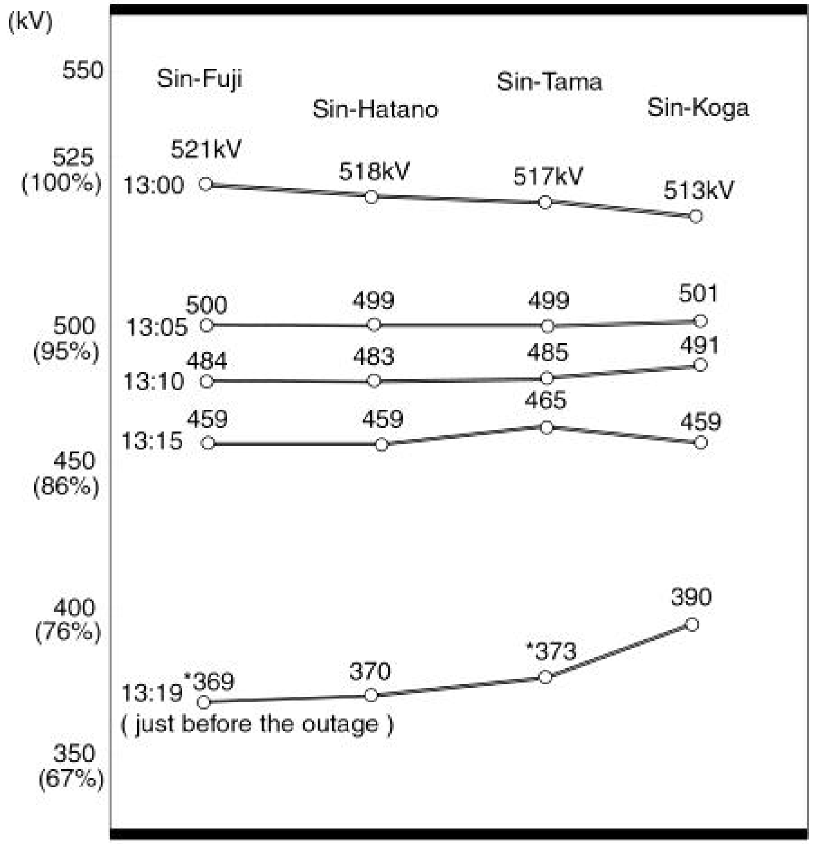
Tokyo Blackout: July 23, 1987

- Result of a voltage collapse
- After lunch load pickup came in at a rate of 400 MW/minute
  - Only sustained for a few minutes
- At 1300, 500 kV voltages were 513 - 521 kV
- At 1310, 500 kV voltages were 483 - 491 kV
- At 1319, 500 kV voltages were 369 - 390 kV
- At this point, the system collapsed
  - 8168 MW of load and 2.8 million customers lost
- Blackout took 19 minutes to develop and 3 hours, 20 minutes to restore

History of Blackouts

Tokyo Blackout
July 23, 1987

Fig. 4 Voltage Drops at Main Substations



* = the estimated value

History of Blackouts

Northeast/Midwest United States and Canadian Blackout: August 14, 2003

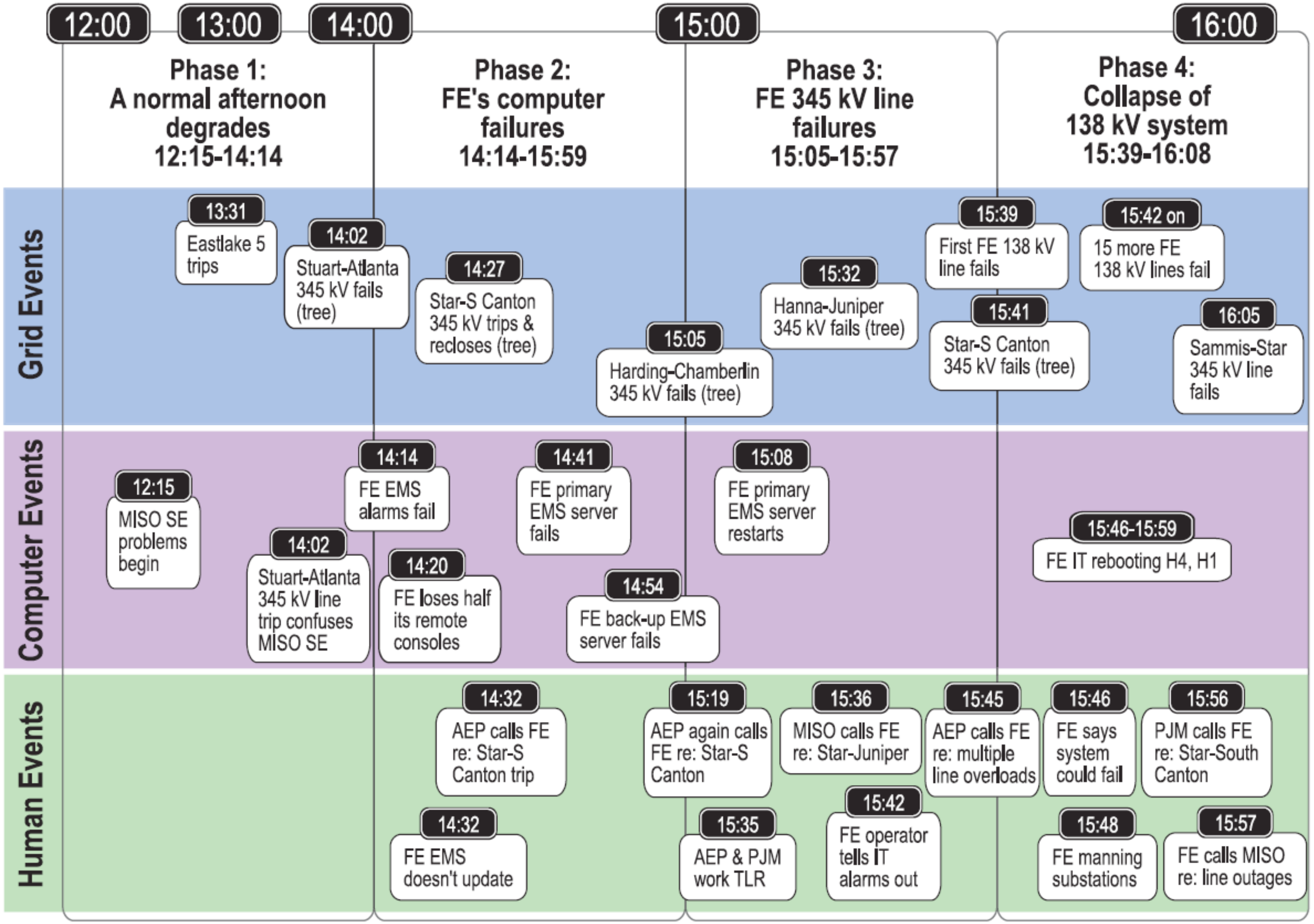
- FE-ATSI was having issues with their EMS
- IT was aware of and working on the issues, but did not communicate with the operators on shift
- Alarm processing had stopped and the operators (and IT) were unaware that they would not be getting SCADA alarms for events
- 345kV and 138 kV line trippings occurred in the FE-ATSI territory and the EMS did not alarm, and were not represented on the FE-ATSI SCADA System

History of Blackouts

Northeast/Midwest United States and Canadian Blackout: August 14, 2003 *(Con't.)*

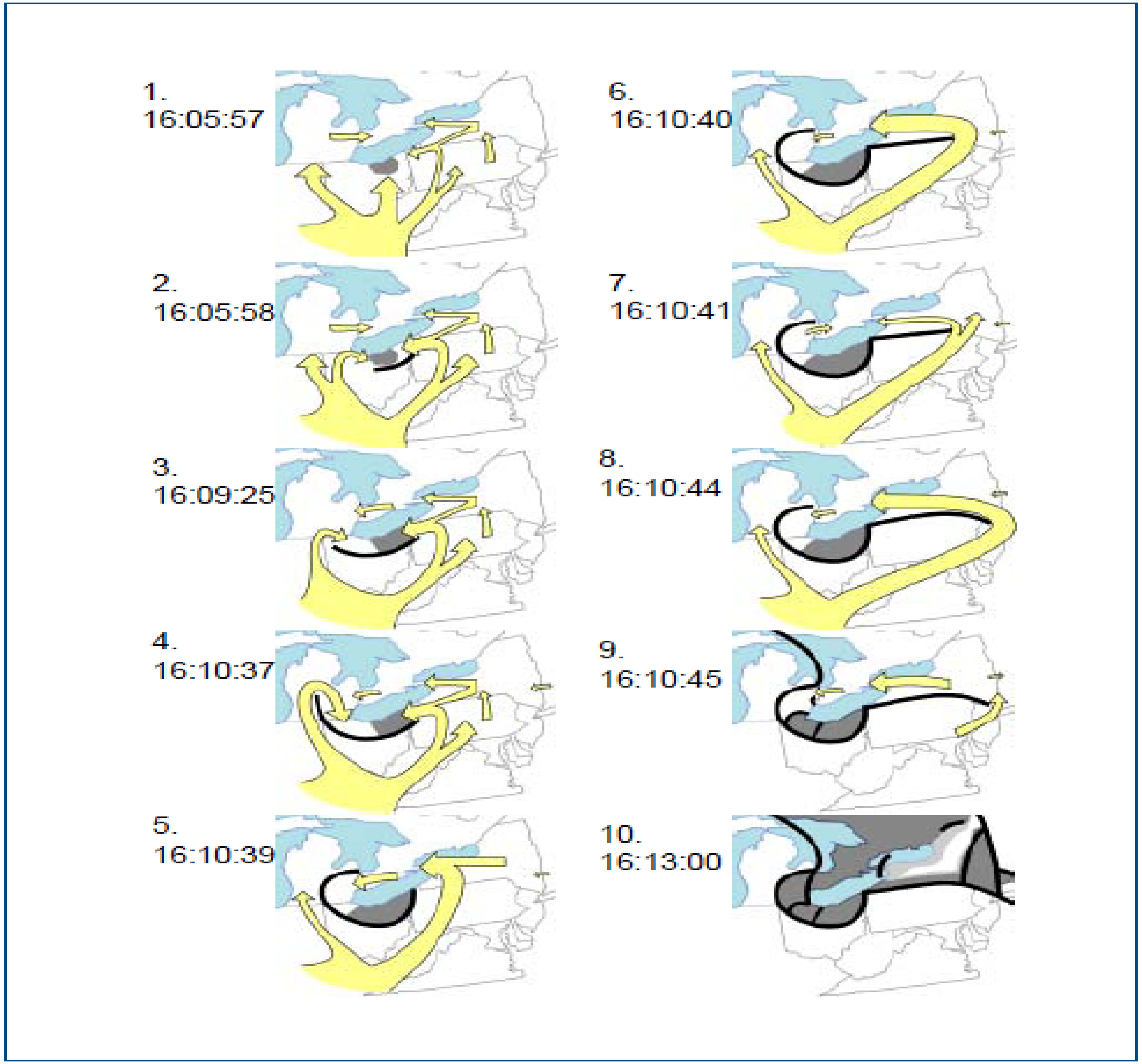
- PJM and MISO saw the resultant flow changes and attempted to question FE-ATSI about the system conditions
- Cascading line trips led to a voltage collapse scenario centered around the Cleveland area
- The low voltages and line trippings caused generating units to begin tripping offline
- The incidents of line trippings, unit trippings, and low voltages expanded throughout the Northeast and into Canada
- The entire event lasted less than 8 minutes

History of Blackouts



History of Blackouts

Cascade Sequence



Legend: Yellow arrows represent the overall pattern of electricity flows. Black lines represent approximate points of separation between areas within the Eastern Interconnect. Gray shading represents areas affected by the blackout.

History of Blackouts

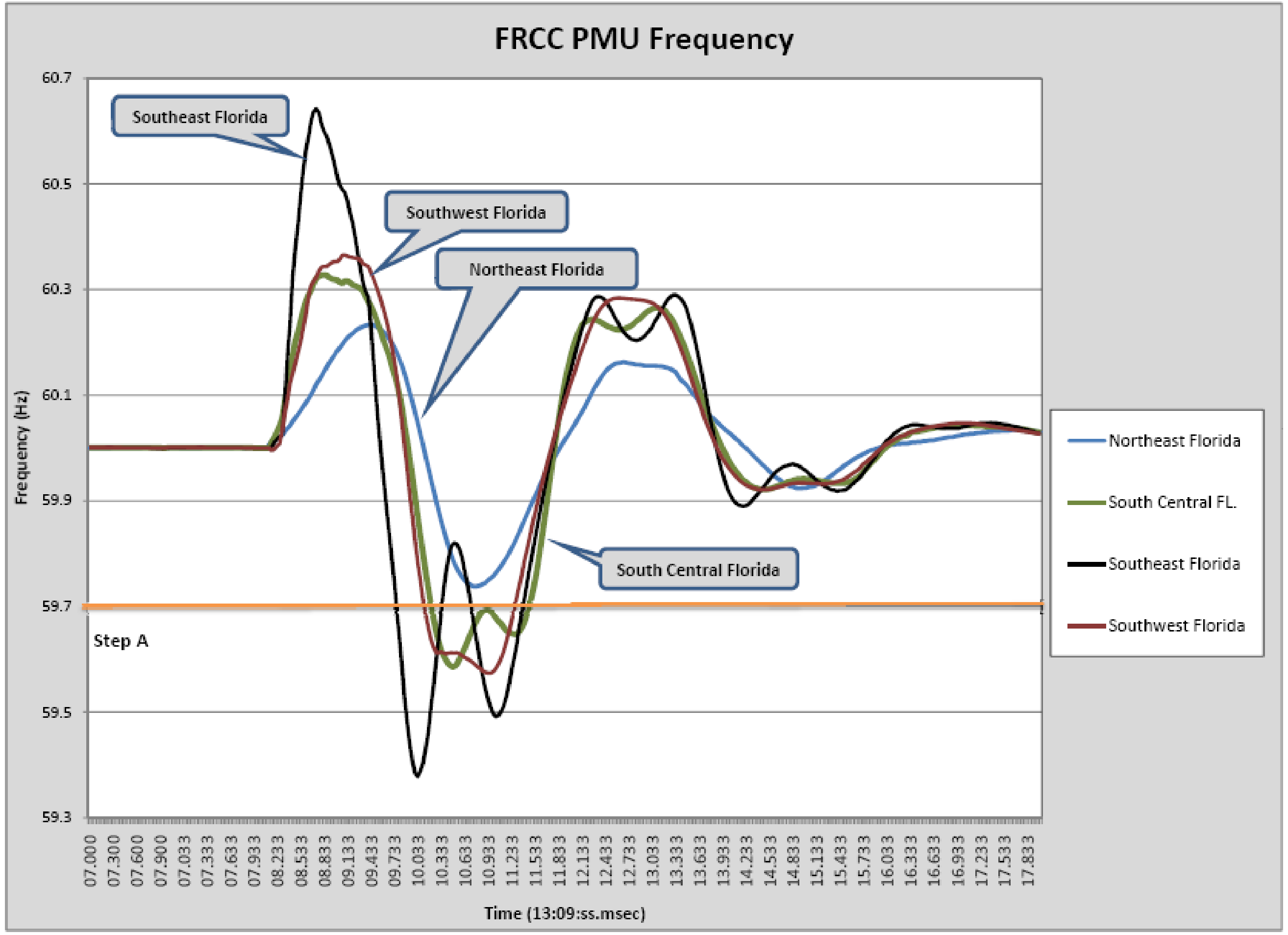
Florida Blackout: Tuesday, February 26, 2008 at 13:09

- Delayed clearing of 3-phase 138kV switch fault at Florida Power and Light, a Miami-area substation (1.7 seconds)
  - Resulted in loss of:
    - 22 transmission lines
    - 1350 MW of load in area of fault
    - 2300 MW of distribution load across southern Florida as a result of under frequency load shedding (59.7 Hz)
    - 2500 MW of generation in area of fault
      - Including 2 Turkey Point Nuclear Units
    - Additional 1800 MW of generation across the region

History of Blackouts *(con't)*

- Florida remained interconnected to Eastern Interconnection throughout the event
  - Majority of load restored within 1 hour
    - All customers restored within 3 hours
  - Final report contained 26 recommendations

History of Blackouts



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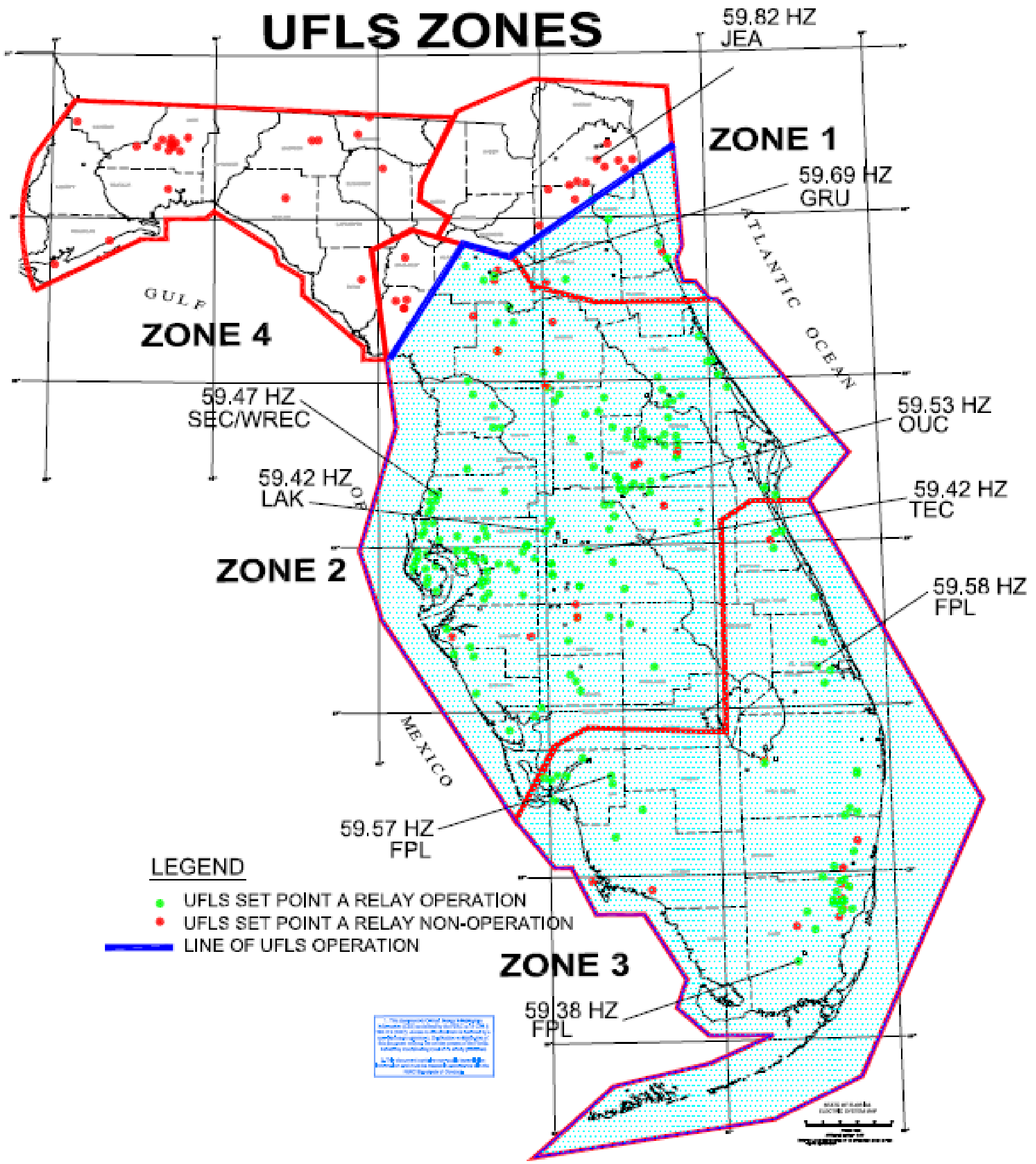
History of Blackouts



FRCC Underfrequency Load Shedding (UFLS) Requirements

1. All load serving members of the FRCC must install automatic underfrequency relays which will disconnect 56% of their customer demand in accordance with the following schedule.

UFLS Step	Frequency - (hertz)	Time Delay [1] - (seconds)	Amount of Load (% of member system)	Cumulative Amount of Load (%)
A	59.7[2]	0.28	9	9
B	59.4	0.28	7	16
C	59.1	0.28	7	23
D	58.8	0.28	6	29
E	58.5	0.28	5	34
F	58.2	0.28	7	41
L	59.4	10.0	5	46
M	59.7	12.0	5	51
N	59.1	8.0	5	56

History of Blackouts

- Local primary and backup relay protection removed from service on energized equipment while troubleshooting equipment malfunction
- Other failed indicators provided false information that led to this decision
  - Insufficient procedures
  - Oversight of field test personnel
    - Approval between field personnel and system operators when protection systems removed from service
    - Communication between control room personnel and control room supervision when protection systems removed from service
    - Protection system changes recommended
    - Training on infrequently received EMS alarms and unusual communication
    - 3-Part communication not consistently used during restoration led to minor confusion
    - Enhanced restoration procedures for under frequency load shed events
    - Under frequency load shed prevented more widespread event

History of Blackouts

Arizona-South California Outages: September 8, 2011

- Late in the afternoon, an 11-minute system disturbance occurred in the Pacific Southwest leading to:
  - Cascading outages
  - Approximately 2.7 million customers without power
- The outages affected parts of Arizona, Southern California, and Baja California, Mexico, and all of San Diego
- The disturbance occurred near rush hour on a business day, snarling traffic for hours

History of Blackouts

- The affected line:
  Hassayampa-N.Gila (H-NG)
  500 kV line,
  Arizona Public Service (APS)
  - A segment of the Southwest Power Link (SWPL)
    - A major transmission corridor
    - Transports power in an east-west direction
    - Generators in Arizona
    - Runs through the service territory of Imperial Irrigation District (IID), into the San Diego area

2200 MW of Nuclear Generation

500 kV
230 kV
161 kV

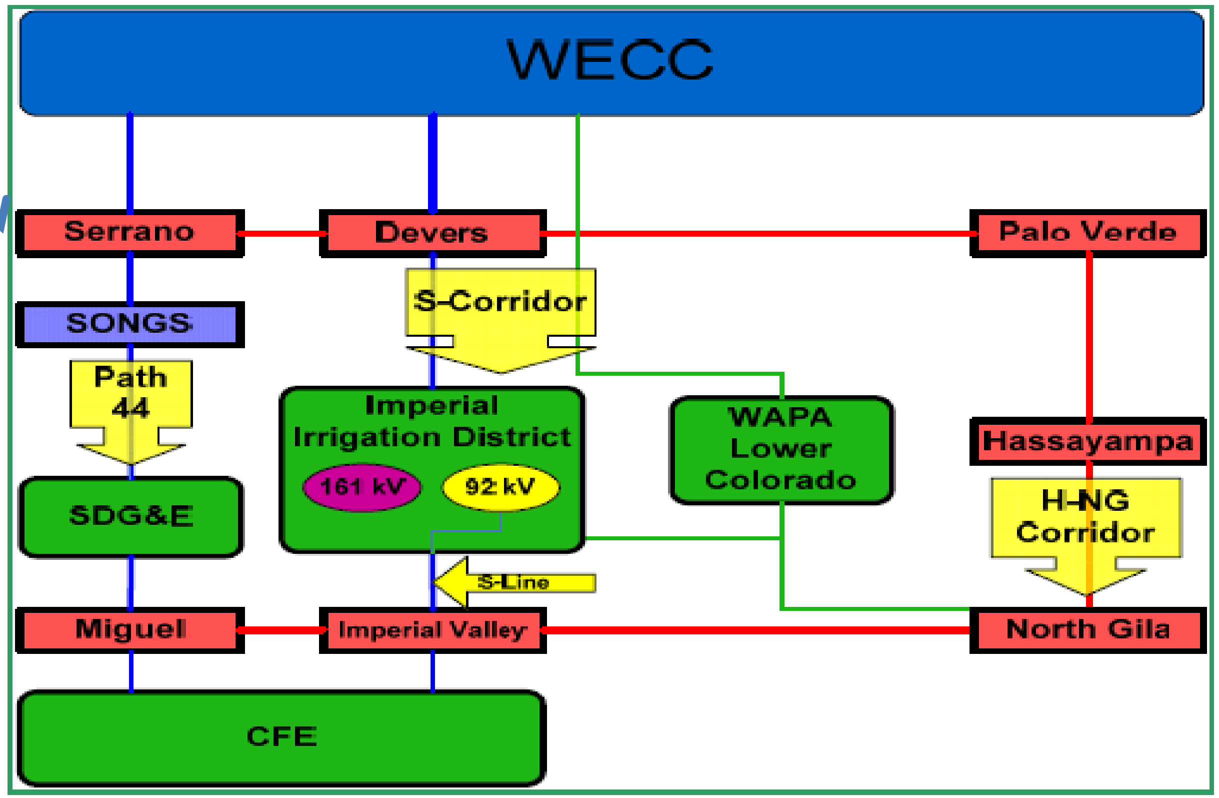


Figure 3: Three Parallel Corridors

History of Blackouts

Arizona-South California Outages

- A technician missed two steps in a switching scheme, causing:
  - Flow redistributions, voltage deviations, and overloads
  - Resulted in transformer, transmission line, and generating unit trippings
  - Initiated automatic load shedding
- Path 44 carried all flows into the San Diego area, and parts of Arizona and Mexico
- The excessive loading on Path 44 initiated an inter-tie separation scheme at SONGS, leading to the loss of the SONGS nuclear units

History of Blackouts

Arizona-South California Outages *(con't.)*

- During the 11 minutes of the event, the WECC Reliability Coordinator issued no directives
- Only limited mitigating actions were taken by the TOP's of the affected areas
- All affected entities had access to power from their own or neighboring systems and, therefore, did not need to use "black start" plans
- Although there were some delays in the restoration process due to communication and coordination issues between entities, the process was generally effective

History of Blackouts

Arizona-South California Outages *(con't.)*

- Significant findings included:
  - Protection settings and coordination
  - Situational awareness of the operators
  - Lack of clarity among all involved operators concerning responsibilities for restoration efforts

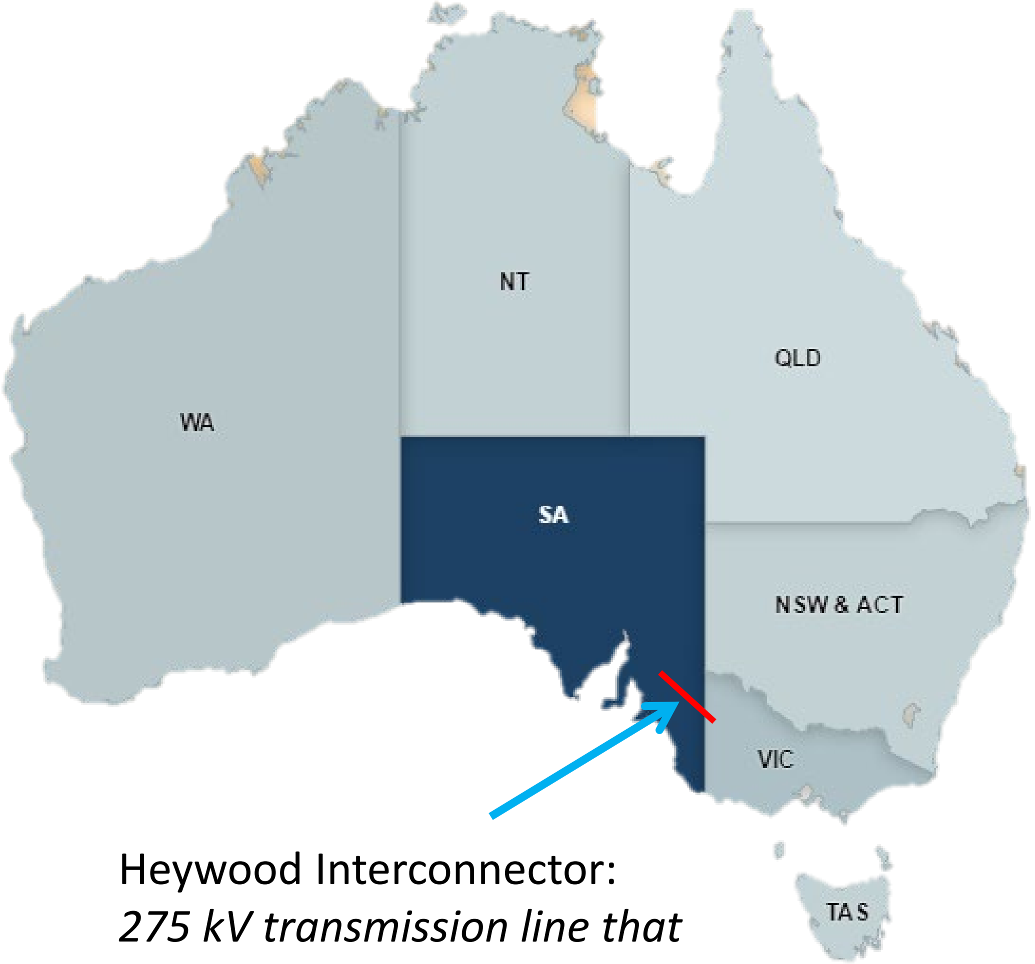
History of Blackouts

Australian Blackout

- AEMO operates Australia's National Electricity Market (NEM) and the interconnected power system in Australia's eastern/south-eastern area

  The National Electricity Market (NEM):

  - Incorporates around 25,000 miles of transmission lines and cables
  - Supplies 200 terawatt hours of electricity to businesses and households each year
  - Supplies around 9 million customers
  - Generates 45,000 MW
  - Trades $7.7 billion in the NEM in 2014-15

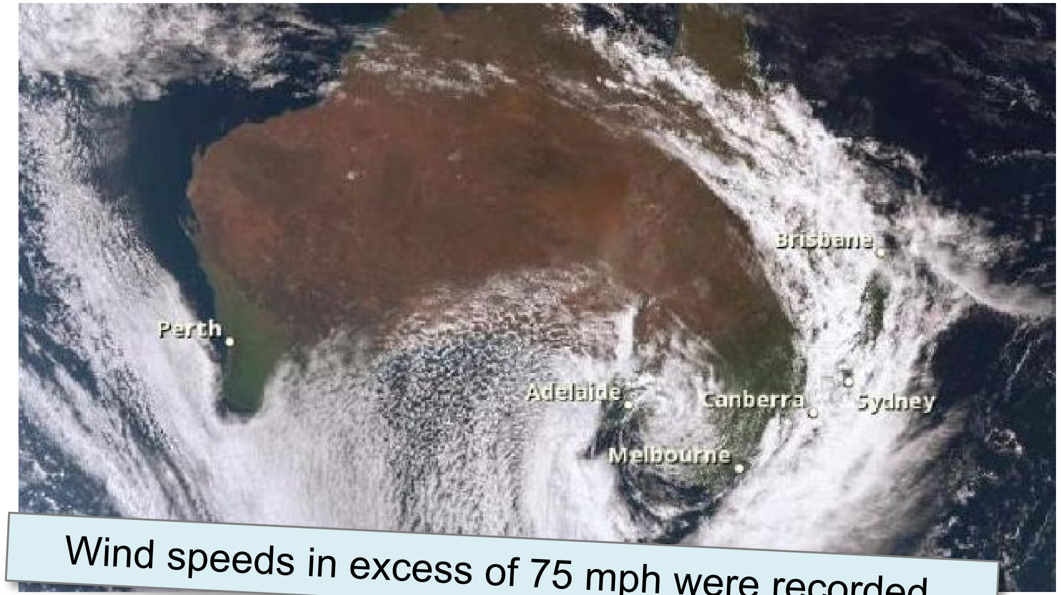


Heywood Interconnector:
275 kV transmission line that permits power flow between South Australia and Victoria

https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM (2017)

History of Blackouts

September 28th, 2016



Wind speeds in excess of 75 mph were recorded.

Extreme weather resulted in the loss of multiple transmission lines and 445 MW of generation of nine wind farms.

The combined loss of wind generation and interchange resulted in the interruption of 1,895 MW resulting in a system blackout.

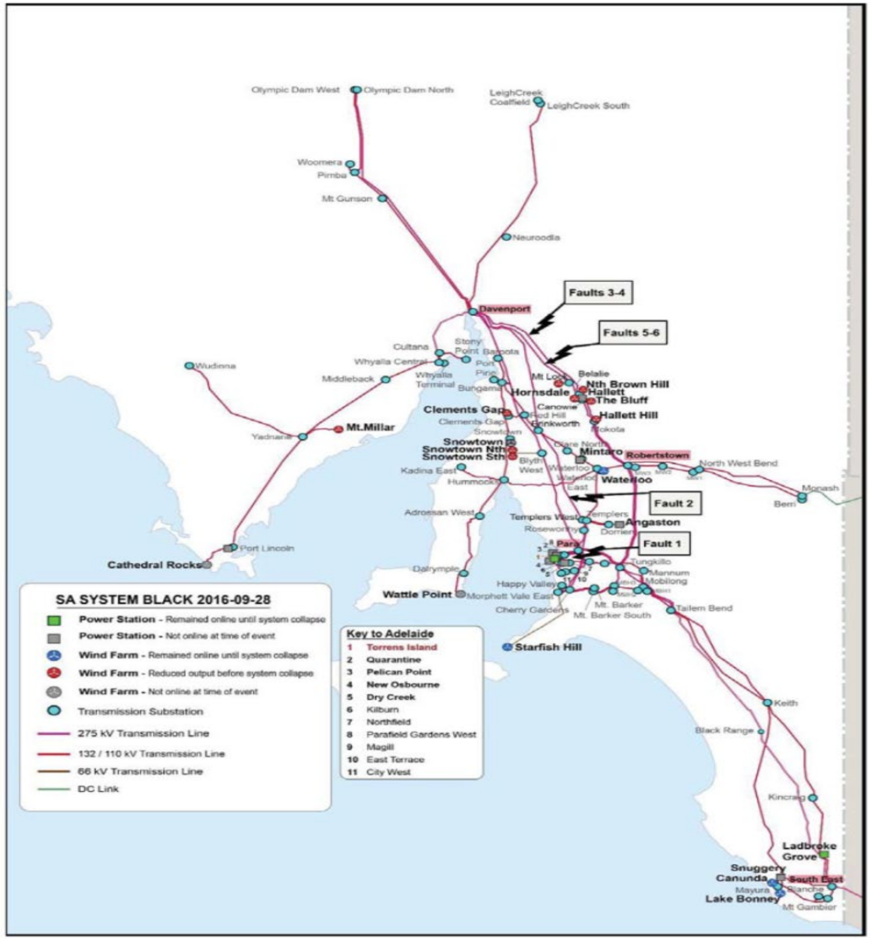
Total customers outaged = 850,000

History of Blackouts

http://www.abc.net.au/news/2016-09-29/political-storm-erupts-after-sa-loses-power/7891098

History of Blackouts

- 6 transmission line faults occurred
  - Major voltage dips on the network over a 2-minute period
- The Murraylink HVDC tie line tripped due to under-voltage conditions
- The Victoria-Heywood Interconnector tripped, the remaining 275KV tie line to Victoria
- South Australia region blacked out



AEMO (2016)

History of Blackouts

Transmission Line Faults

Fault number	Time	Details
1	16:16:46	Fault on Northfield-Harrow 66kV feeder in the Adelaide metropolitan area. Trip and successful auto-reclose. Voltage dipped to 85% at Davenport.
2	16:17:33	Two phase to ground fault on the Brinkworth – Templers West 275kV transmission line. No reclose attempt. Voltage dipped to 60% at Davenport.
3	16:17:59	Single phase to ground fault on the Davenport – Belalie 275kV transmission line. Faulted phase successfully auto-reclosed. Voltage dipped to 40% at Davenport.
4	16:18:08	Single phase to ground fault on the Davenport – Belalie 275kV transmission line. No auto-reclose attempted as fault is within 30 seconds of the previous fault Line opened on all three phases and remained out of service. Voltage dipped to 40% at Davenport.
5	16:18:13	Single phase to ground fault on the Davenport – Mt Lock 275kV transmission line. Voltage dipped to 40% at Davenport.
	16:18:14	Single phase to ground fault on the Davenport – Mt Lock 275kV transmission line due to unsuccessful auto-reclose. Fault still on line. Line opened on all three phases and remained out of service. Voltage dipped to 40% at Davenport.

AEMO (2016)

History of Blackouts

Wind Farm Response

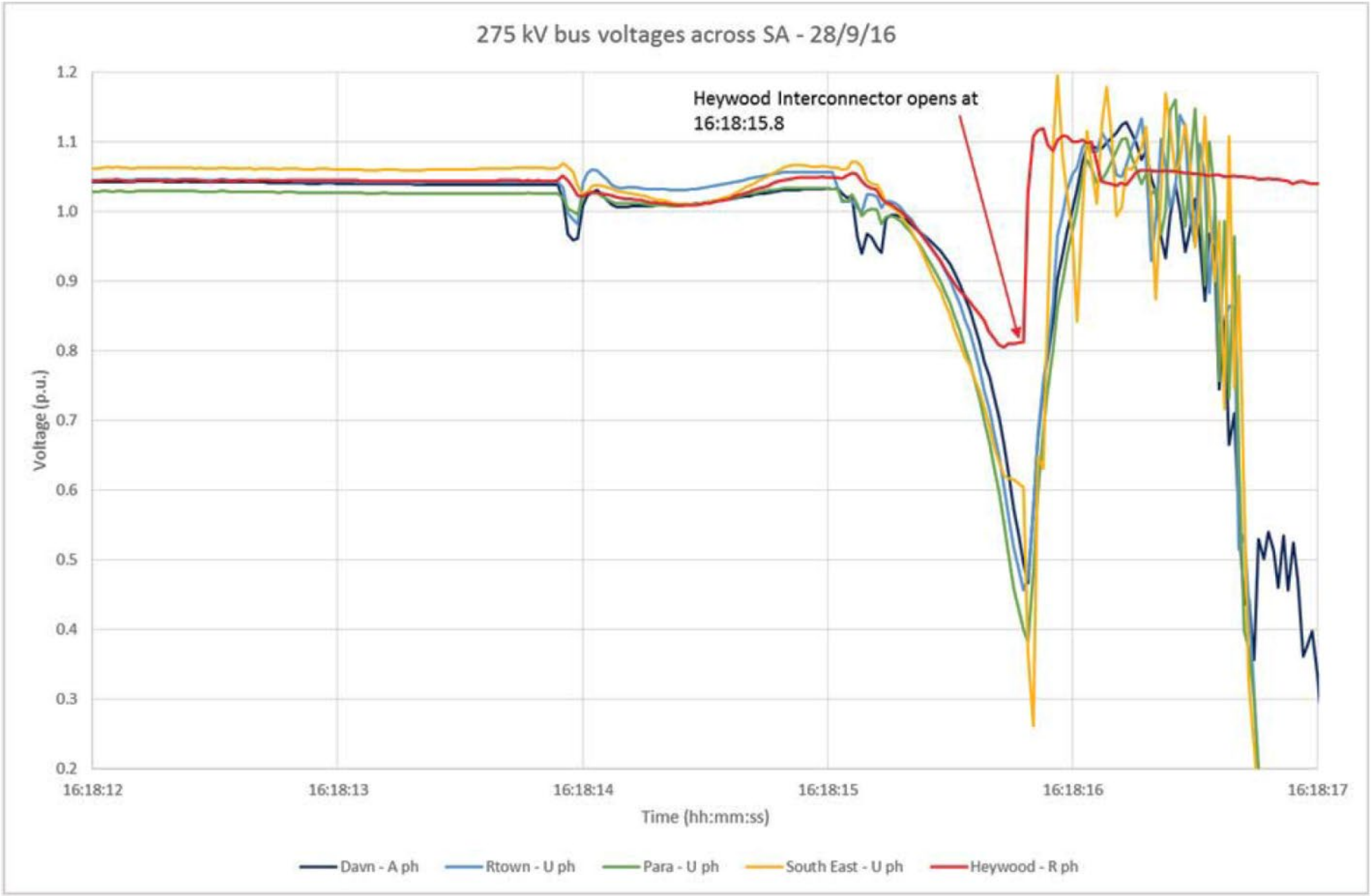
- 445 MW of wind generation tripped offline due to relay activation, designed to protect the turbines against
  - Under voltage conditions (ride-through mode)
  - Wind operators were aware of these limitations but the grid operator was not

Wind farm	Pre-set limit to ride-through events in 120 seconds	Number of times wind turbines activated ride-through mode	Last state of wind turbines prior to system voltage collapse	Output pre-event at 16:18:07 [MW]	Output just prior to separation at 16:18:15.4 [MW]
Canunda	9	1	Operational	27.7	27.2
Lake Bonney 1	42618	0	Operational	77.7	76.5
Lake Bonney 2,3	9	0	Operational	171.9	158.7
Waterloo	9	5	Operational	96.6	72.9
				Expected MW Reduction	**38.6**
Clements Gap	2	3	Disconnected	14.5	-0.5
Hallett	2	3	Most turbines disconnected	34.5*	1.7*
Hallett Hill	2	3	Most turbines disconnected	41.3*	19.5*
Mt Millar	Not known	5	Stopped Operation	67.0**	2.8**
North Brown Hill	2	3	Most turbines disconnected	85.5	11.0
Hornsdale	5	6	Stopped Operation	83.9	-1.1
Snowtown North	5	6	Stopped Operation	65.5	-0.8
Snowtown South	5	6	Stopped Operation	42.1	-1.2
The Bluff	2	3	Most turbines disconnected	41.9	-0.3
				Unexpected MW Reduction	**445.1**
Total MW output				**850.1**	**366.4**
Total MW Loss					**483.7**

AEMO (2016)

History of Blackouts

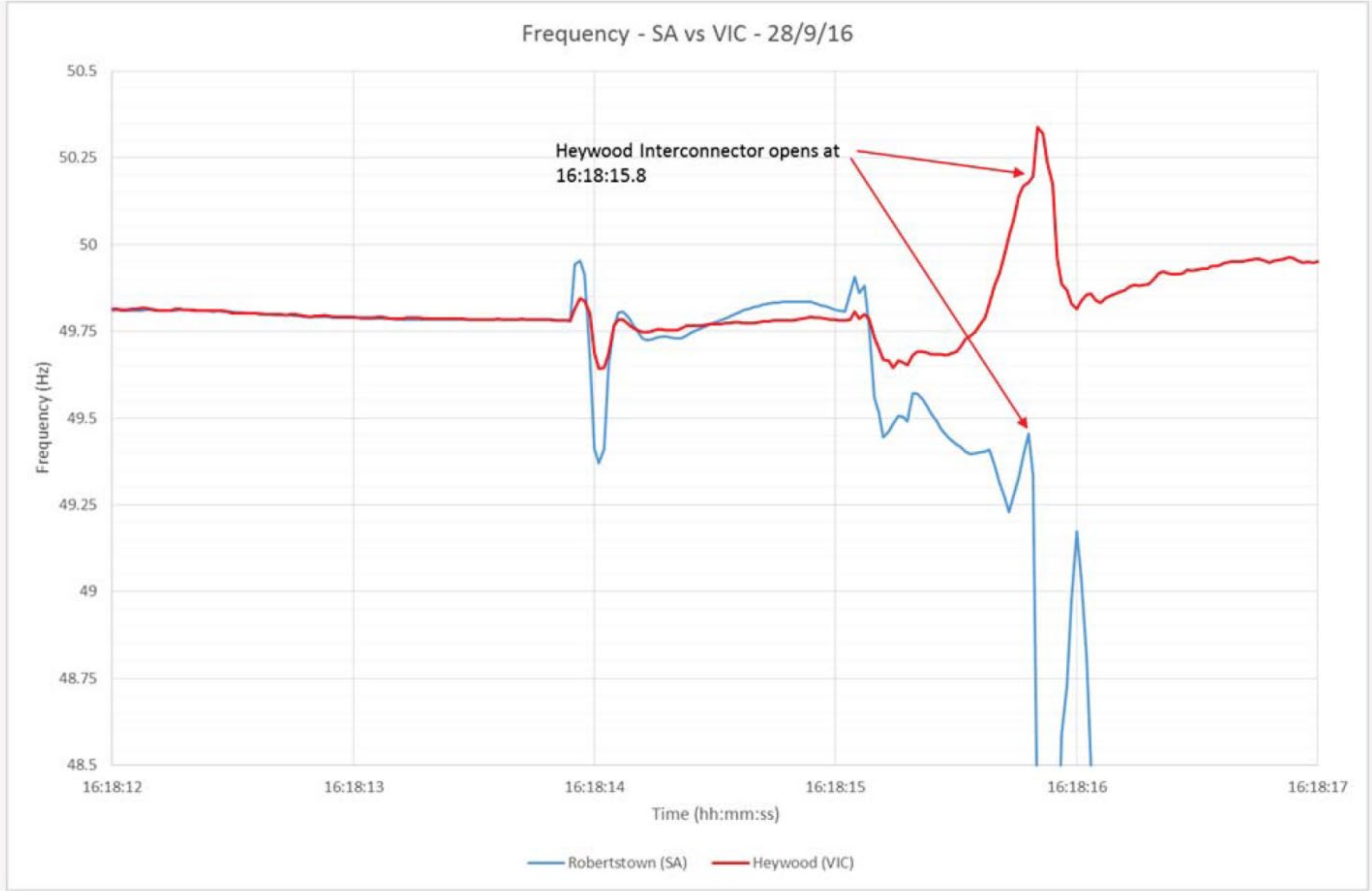
Voltage Profile During Event



AEMO (2016)

History of Blackouts

Frequency Profile During Event



AEMO (2016)

History of Blackouts

- Time for total customer restoration: 7 ½ hours
- System Restart Ancillary Service (SRAS) “black start” units did not operate as designed, even though they had been tested within the operating year
  - SRAS 1 could not start due to the switching sequence used. Corrective measures have been put in place and tested
  - SRAS 2 suffered a stator ground fault after 15 seconds of operation. This problem has been corrected
- AEMO power market prices spiked from $60 to $9000/MWhr*
  - AEMO suspended market operations during the event
  - The Australian government is currently reviewing the role of renewable vs. traditional forms of generation

*http://www.abc.net.au/news/2016-09-25/sa's-power-price-spike-sounds-national-electricity-alarm/7875970

History of Blackouts – Cyber Attack

Ukraine Blackout

- December 23rd 2015
- Three Ukrainian distribution companies were attacked
  - 225,000 customers outaged
- Seven 110-kV and twenty-three 35-kV substations were disconnected for 3 hours

History of Blackouts – Cyber Attack

- Initially thought to be solely the Black Energy 3 virus the attack included multiple elements to include:
  - Spear phishing of business networks
  - Telephone denial-of-service attack on the call center to delay/hamper restoration efforts
  - Use of a KillDisk program to delete targeted files and logs
  - Use of virtual private networks (VPNs) to enter networks
  - The use of keystroke loggers to perform credential theft and enter critical networks

NERC (2016)

History of Blackouts – Cyber Attack

Wired.com Article

The operator grabbed his mouse and tried desperately to seize control of the cursor, but it was unresponsive. Then as the cursor moved in the direction of another breaker, the machine suddenly logged him out of the control panel. Although he tried frantically to log back in, the attackers had changed his password preventing him from gaining re-entry. All he could do was stare helplessly at his screen while the ghosts in the machine clicked open one breaker after another, eventually taking about 30 substations offline. The attackers didn't stop there, however. They also struck two other power distribution centers at the same time, nearly doubling the number of substations taken offline and leaving more than 230,000 residents in the dark. And as if that weren't enough, they also disabled backup power supplies to two of the three distribution centers, leaving operators themselves stumbling in the dark.

https://www.wired.com/2016/03/inside-cunning-unprecedented-hack-ukraines-power-grid/

History of Blackouts – Cyber Attack

Event Analysis

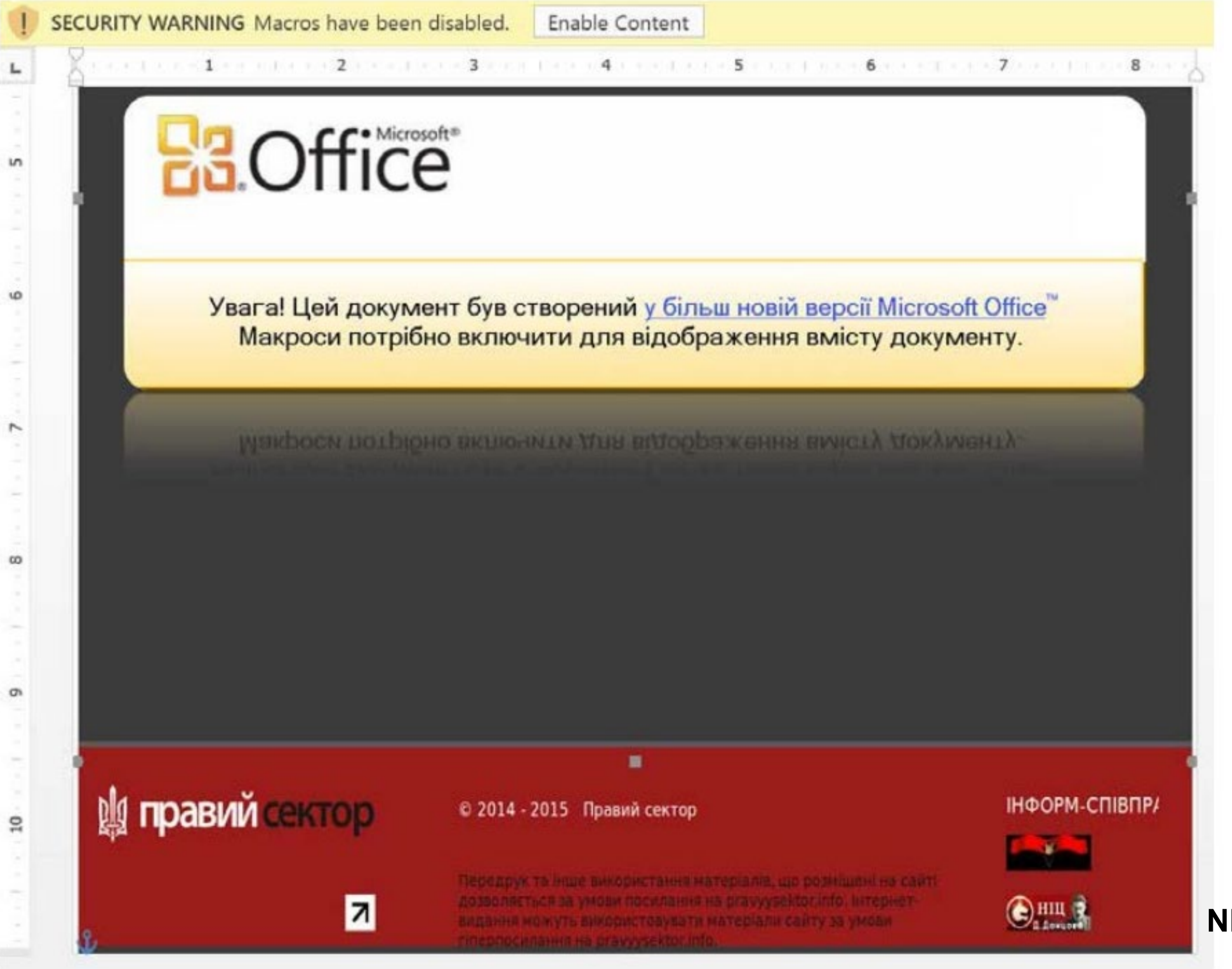
The NERC report identifies the following as the root cause of the event:

"The outages were caused by the use of the control systems and their software through direct interaction by the adversary. All other tools and technology, such as BlackEnergy 3 and KillDisk, were used to enable the attack or delay restoration efforts."

History of Blackouts – Cyber Attack

Clicking "Enable Content" gave the Black Energy 3 virus user access to energy networks

Black Energy 3 Macro



NERC (2016)

Figure 6: A Sample of a BlackEnergy 3 Infected Microsoft Office Document[27]

History of Blackouts

- Production
  - Loss of productivity
  - Loss of product or property
- Health
  - Food contamination
  - Medication problems
  - Anxiety
- Safety
  - Traffic accidents
  - Accidents due to visibility problems
  - Civil unrest

Defining a Black Start Unit

PJM defines a Black Start Unit as:

- A generating unit that has equipment enabling it to start without an outside electrical supply or a generating unit with a high operating factor (subject to Transmission Provider concurrence) with the demonstrated ability to automatically remain operating, at reduced levels, when disconnected from the grid

NERC Requirements for Critical Black Start (EOP-005-2)

- Each GOP shall participate in the RC's restoration drills, exercises, or simulations as requested by the Reliability Coordinator
- Each GOP with a Blackstart Resource shall have documented procedures for starting each Blackstart Resource and energizing a bus
- Each GOP with a Blackstart Resource shall notify its TOP of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the TOP's restoration plan within 24 hours following such change

NERC Requirements for Critical Black Start (EOP-005-2)

- Each TOP shall have Blackstart Resource testing requirements to verify that each Blackstart Resource is capable of meeting the requirements of its restoration plan. These Blackstart Resource testing requirements shall include:
  - The frequency of testing such that each Blackstart Resource is tested at least once every three calendar years

NERC Requirements for Critical Black Start (EOP-005-2)

- Each GOP with a Blackstart Resource shall perform Blackstart Resource tests, and maintain records of such testing, in accordance with the testing requirements set by the TOP to verify that the Blackstart Resource can perform as specified in the restoration plan
  - Testing records shall include at a minimum: name of the Blackstart Resource, unit tested, date of the test, duration of the test, time required to start the unit, an indication of any testing requirements not met under Requirement 9
  - Each GOP shall provide the Blackstart test results within 30 calendar days following a request from its RC or TOP

NERC Requirements for Critical Black Start (EOP-005-2)

Each GOP with a Blackstart Resource shall provide a minimum of two hours of training every two calendar years to each of its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus.

The training program shall include training on the System restoration plan including coordination with the TOP.

PJM Requirements for Critical Black Start: Capability

- The unit must have the ability to close its output breaker to a dead bus within three hours of the request from the local TO or PJM
- Based on critical load timing requirements, some Black Start resources may be required to adhere to less than a three hour start time
  - These units will be notified of the timing requirement and tested to it during the annual Black Start testing

PJM Requirements for Critical Black Start: Capability

- Designated critical black start generation is identified as such in each Transmission Owners restoration plan
- The generating unit owner and PJM have agreed that the unit should be designated as black start capable
- The unit is located where black start capability is determined by PJM and all affected TOs to be useful to the restoration process and will be incorporated into the restoration plans of the affected TOs

PJM Requirements for Critical Black Start: Performance Standards

- Ability to self-start without any outside source of power within three hours, or the time defined in the TOs restoration plan can be demonstrated:
  - Through testing or the ability to operate at reduced levels when automatically disconnected from the grid
- Ability to close into a de-energized bus can be demonstrated by either:
  - Physically closing the generator breaker connected to a dead bus while the unit is running ***or***
  - A test that simulates closing the generator breaker while only the generator side of the breaker is energized

PJM Requirements for Critical Black Start: Performance Standards

- Ability to operate at reduced levels when automatically disconnected from the grid can be demonstrated by:
  - Physically removing the unit from the grid while the unit is running or,
  - A test that simulates removing the unit from the grid
- Capability to maintain frequency under varying load can be demonstrated by:
  - Picking up an isolated block of load
  - Dynamic off-line testing of the unit's governor controls

PJM Requirements for Critical Black Start: Performance Standards

- Capability to maintain voltage under varying load can be demonstrated by:
  - Picking up an isolated block of load or,
  - Producing both leading and lagging VARs by varying the voltage setting while the unit is synchronized to the system or,
  - Dynamic off-line testing of the voltage controls
- Ability to maintain rated output for a duration as identified by the TO's restoration plan
  - Specific gas supply requirements for gas fueled black start units should be considered in the TO's restoration plan such as:
    - Electric feed to gas gate valves
    - Local gas compressors needed to maintain supply

PJM Requirements for Critical Black Start: Performance Standards

- Each black start generation owner must maintain procedures for the start-up of black start generation at each station
  - These standards shall remain in effect for the duration of the commitment

PJM Black Start Unit Requirements

- Minimum Critical Black Start Requirement for each transmission zone consists of the following components:
  - Critical cranking power load
    - Units with a hot-start time of 4 hours or less (including the load required to supply scrubbers, where necessary)
  - Off-site Nuclear Station Light and Power (to maintain safe shutdown) as defined in each plant’s Nuclear Plant Interface Requirements (NPIR) document
  - Critical Natural Gas Infrastructure (such as electric compressors)
    - A list of critical substations that serve Gas Infrastructure critical load will be documented in the Transmission Owner’s Restoration Manual

Priority Load

- Priority load provided by black start or other generation
  - Cranking power to generation with a greater than 4-hour start-up time
  - Power to electric infrastructure
    - Light and power to substations
    - Pumping plants for underground cable systems
  - Critical communication equipment
  - Critical command and control facilities
  - Underfrequency load shed circuits

PJM Black Start Unit Requirements

- Must be tested annually
  - To ensure unit can start when requested from a “blackout” state
  - To ensure personnel are familiar with procedure
  - Have the ability to self-start without any outside source of power
  - Have the ability to close unit onto a dead bus within 3 hours of the request to start
  - Have the ability to run for 16 hours, or as defined by TO restoration plan
    - GOs must notify PJM and the TO if a critical blackstart fuel resource at max output falls below 10 hours
  - Have the ability to maintain frequency and voltage under varying load
  - The company must maintain black start procedures for each unit

PJM Black Start Unit Requirements

- Exceptions or additions to the criteria above will be allowed with PJM approval:
    - SOS-T endorsement will be sought for these exceptions and additions
    - One example could be to address coping power needs for steam units that cannot be supplied by resources other than black start
    - Exceptions to critical cranking power are made for intermittent generation (i.e. wind, solar)
    - Exceptions to critical cranking power will be considered on a case by case basis for:
        - Complex cranking paths for minimum ICAP gain
        - Non-dispatchable units or units with very high minimum limits

PJM Black Start Unit Requirements

- Required Black Start = 110% (Critical Load Requirement) on a locational basis
  - Accounts for an average forced outage rate (5%) plus an allowance for additional, unexpected Critical Load (5%)
  - Allows for redundancy for restoration even if some Black Start resources are unavailable, and a variance between Critical Load calculations and actual needs
- PJM will ensure, at a minimum, an allocation of two Black Start resources to each Transmission zone with a Critical Load requirement
  - Black start resources are not required to be physically located within the zone to which they are allocated (Cross Zonal Coordination)

Black Start Unit Procurement

PJM Actions:

- In its role as Transmission Operator (TOP), is responsible for selecting the Black Start resources for a system restoration plan
- Would work closely with the TOs to identify these units based on:
  - Critical Load requirements
  - Available Black Start resources
  - Minimum number of Black Start resources allocated to a zone
  - Possible cross zonal coordination opportunities
    - Manual 36: System Restoration Attachment A: Minimum Critical Black Start Requirement

Black Start Unit Procurement

PJM Actions:

- Utilize the start time parameters and test data to evaluate the Black Start resources and whether these resources will meet the requirements of the restoration plans
  - May require some Black Start resources to adhere to less than a 3 hour start time given critical load restoration timing requirements
    - These units will be notified of this timing requirement and tested to it during annual Black Start testing
  - Recognizes that Black Start resources with three hour start times may not appropriate to meet nuclear power off-site safe-shutdown load restoration requirements. The target restoration time for off-site power to nuclear stations is 4 hours

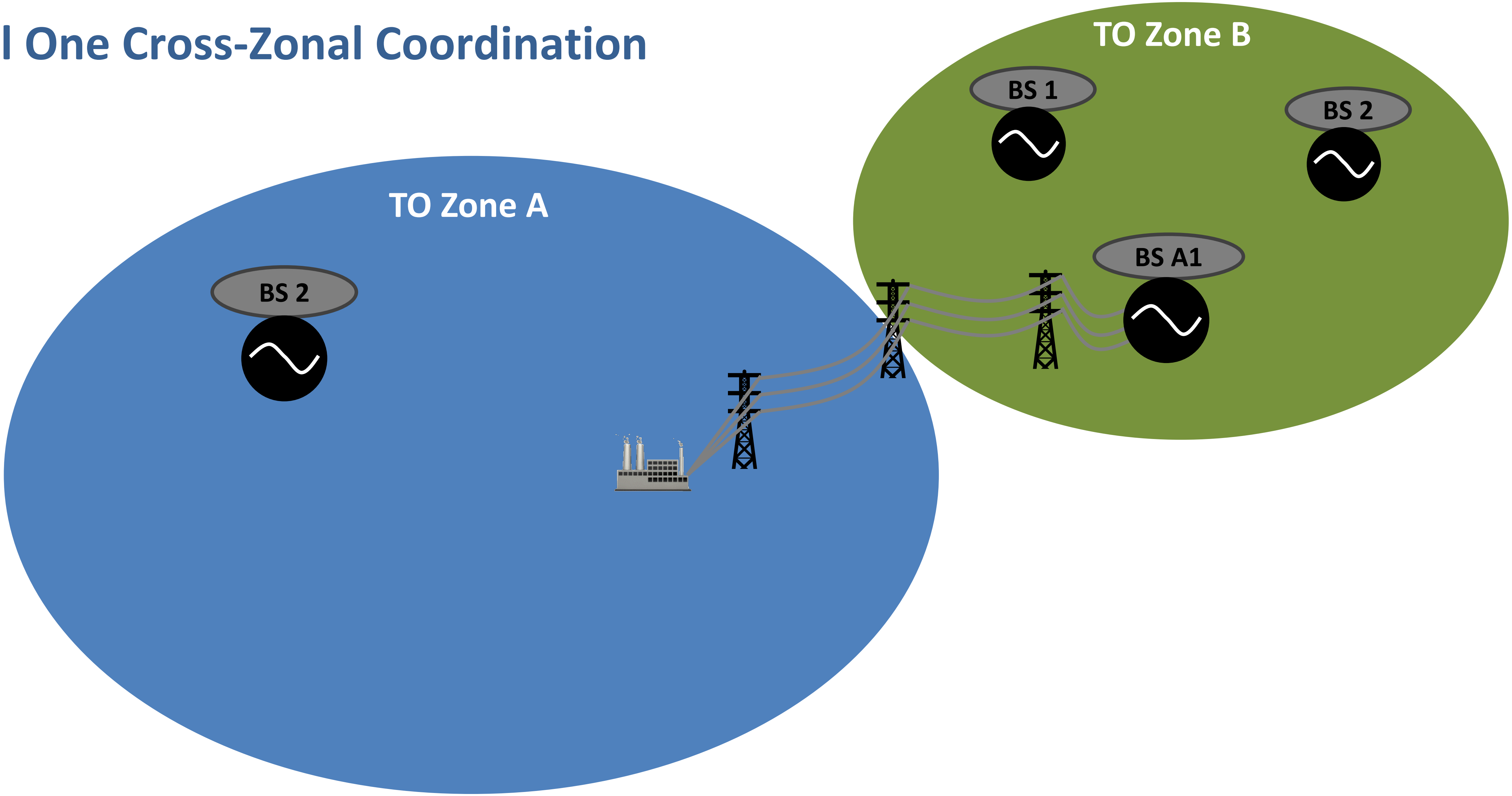
Black Start Unit Procurement

PJM Actions:

- In collaboration with the TOs, will select Black Start units to meet Critical Load requirements during the 5 year Black Start Selection process described in PJM Manual M-14D, Generator Operational Requirements
- Will utilize the Black Start Replacement Process, as described in PJM Manual M-14D for changes to Black Start availability or Critical Load requirements that occur within the 5 year period

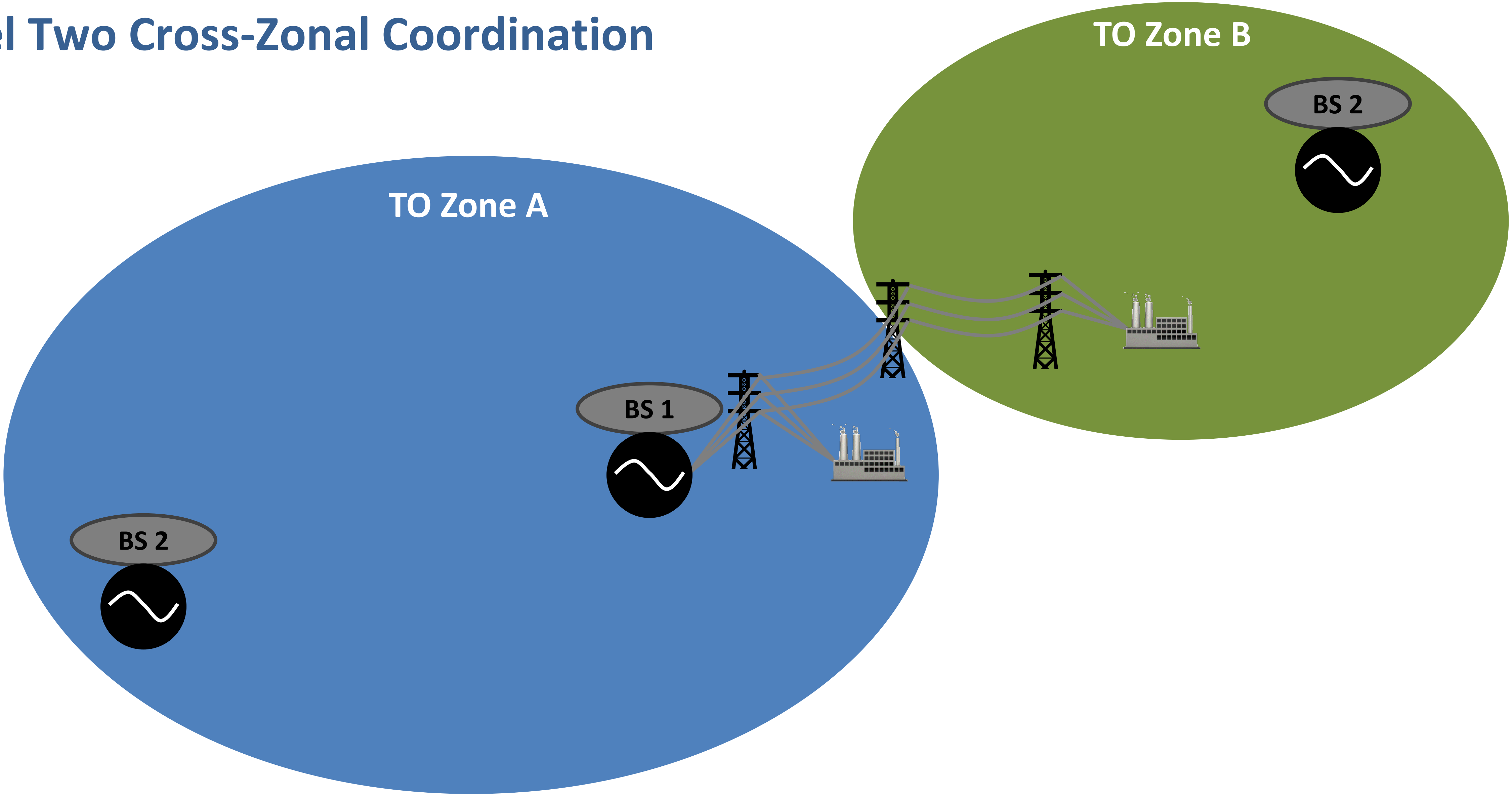
Cross-Zonal Coordination

Level One Cross-Zonal Coordination



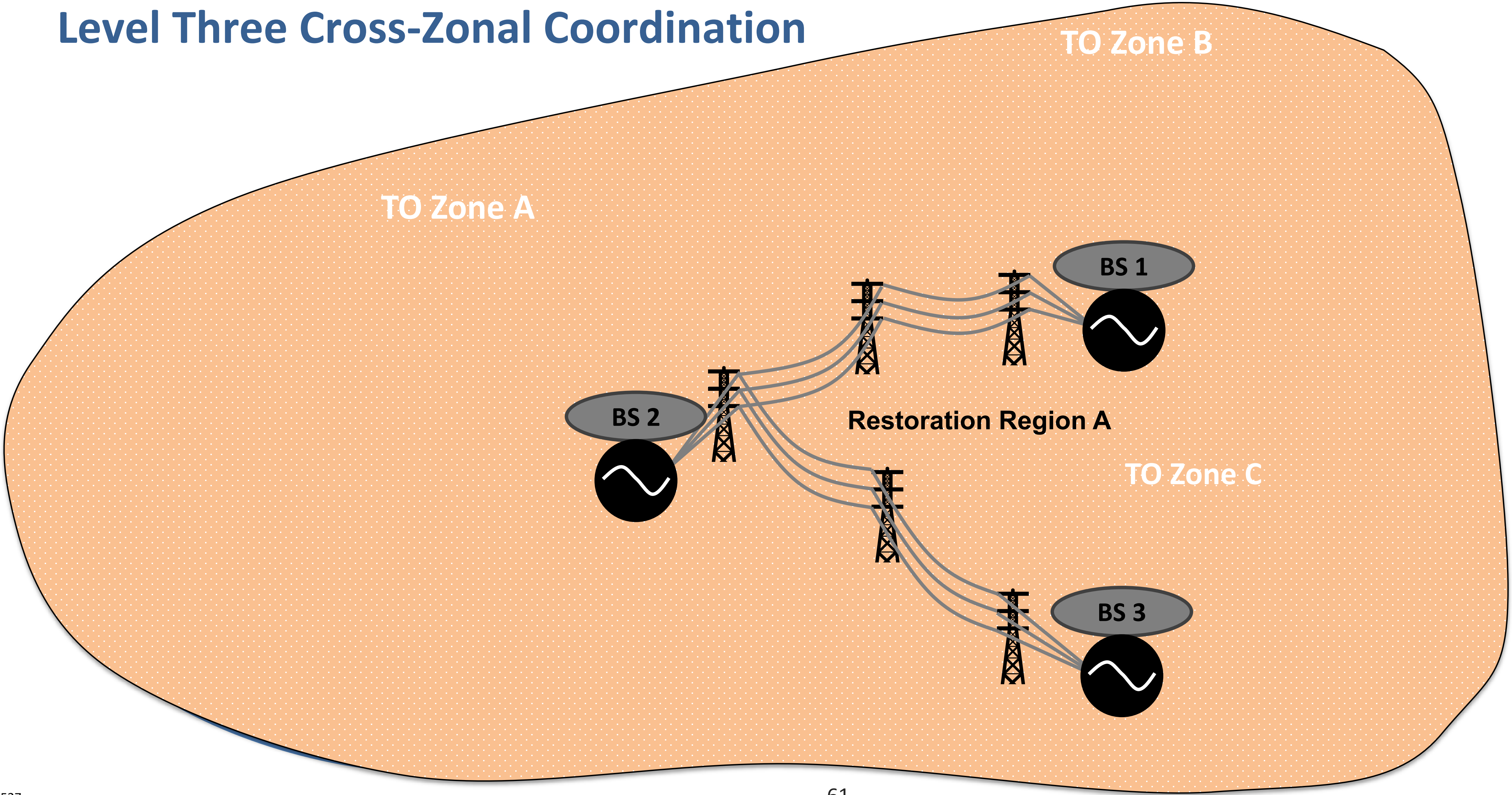
Cross-Zonal Coordination

Level Two Cross-Zonal Coordination



Cross-Zonal Coordination

Level Three Cross-Zonal Coordination



Cross Zonal Coordination

- Level One, Two, and Three Cross Zonal Coordination would be pursued to:
  - Eliminate a Black Start shortage within the zone
  - Meet critical load restoration timing requirements
  - Improve restoration speed and/or efficiency
  - Significantly reduce Black Start cost

Cross Zonal Coordination

- The criteria for this analysis include:
  - Reliability Requirements
    - Procuring sufficient Black Start resources to meet critical load requirements
    - Meeting critical load restoration timing requirements
    - Meeting redundancy requirements (equipment failures)
  - Efficiency Opportunities
    - Cost Savings (1/2 benefit to cost required savings ratio)
      - Black Start unit cost difference
      - Potential additional TO costs including coordination costs, CIP related costs and other costs the TO might incur
    - Potential for increased efficiency and speed of restoration

Cross Zonal Coordination

- The following considerations will be evaluated when analyzing cross-zonal coordination options:
  - Technical feasibility requirements:
    - Maintaining voltages within limits
    - Maintaining MW flows within thermal limits
    - Maintaining dynamic stability of generation
    - Timing requirements of serving critical load
    - Test history and performance history of Black Start resource

Cross Zonal Coordination

- The following considerations will be evaluated when analyzing cross-zonal coordination options (cont.):
  - Complexity considerations
    - Amount of switching to establish cranking path(s)
    - Characteristics of cranking path (length, geography, travel time, number of substations, voltage level, etc)
    - Staffing availability (field/control room) to support building cranking path to neighboring area

Cross Zonal Coordination

- The following considerations will be evaluated when analyzing cross-zonal coordination options (cont.):
  - SCADA versus Manual control
    - Logistical coordination
    - Adjacent TO zones only (do not cross 3 or more zones)
    - Type of load restored in each TO zone
    - Potential additional TO costs incurred to enable cross zonal coordination
    - Number of TO zones in coordination with a single TO zone
  - TO/State Relationship considerations
    - States may want priority of restoration to remain local

Company Hourly Restoration Report *

Date:	Time:
Reporting Company:	
Transmission Zone:	
Company Contact:	Estimated Time to Complete Total Restoration: Date: Time:

If no changes since last report submitted, report is not required

GENERATION REPORT:	MW	LOAD RESTORATION REPORT:	MW
Generation: Capacity on Line		Total Customer Load Restored	
Generation: Energy on Line		# Of Customers Restored (000)	
# Of Generators on Line		% Customers Restored	
# Of Subsystems (Islands)		% Customers Restored Last Hour	
CAPACITY DUE IN:			
Generation in One Hour (1)			
Generation in Three Hours (3)			
Generation in six Hours (6)			

UNITS ON LINE SINCE LAST REPORT

Station	Unit	MW	Station	Unit	MW

UNITS EXPECTED DURING NEXT HOUR

Station	Unit	MW	Station	Unit	MW

Damage detected since last report / comments:

CRANKING POWER

From Company to Station	kV	Time	From Company to Station	kV	Time

* May be required more often. Information to be compiled by TO operators for units within their zone and submitted to PJM.

Exhibit 14: Company Hourly Restoration Report

Generator Information Reporting Requirements

- Following an event or disturbance, unit personnel shall begin an immediate inspection, communicating the status of the unit to the Generation Operator
- Generation Operators that control the output of a generation resource must take or arrange for any or all of the following actions as directed by PJM to manage, alleviate, or end an emergency, or such actions as PJM deems appropriate for these purposes:
  - Reporting the operating status, condition, and availability
  - Estimates of unit return times
- Generation Operators shall collect information, and notify PJM of known generation capabilities, equipment damage, and other pertinent information (Done thru the initial and hourly generation reports submitted thru the respective Member Company Transmission Owners)
- Transmission Owner Operators and Generation Operators shall notify key personnel and generation plant operators regarding the extent of the outage

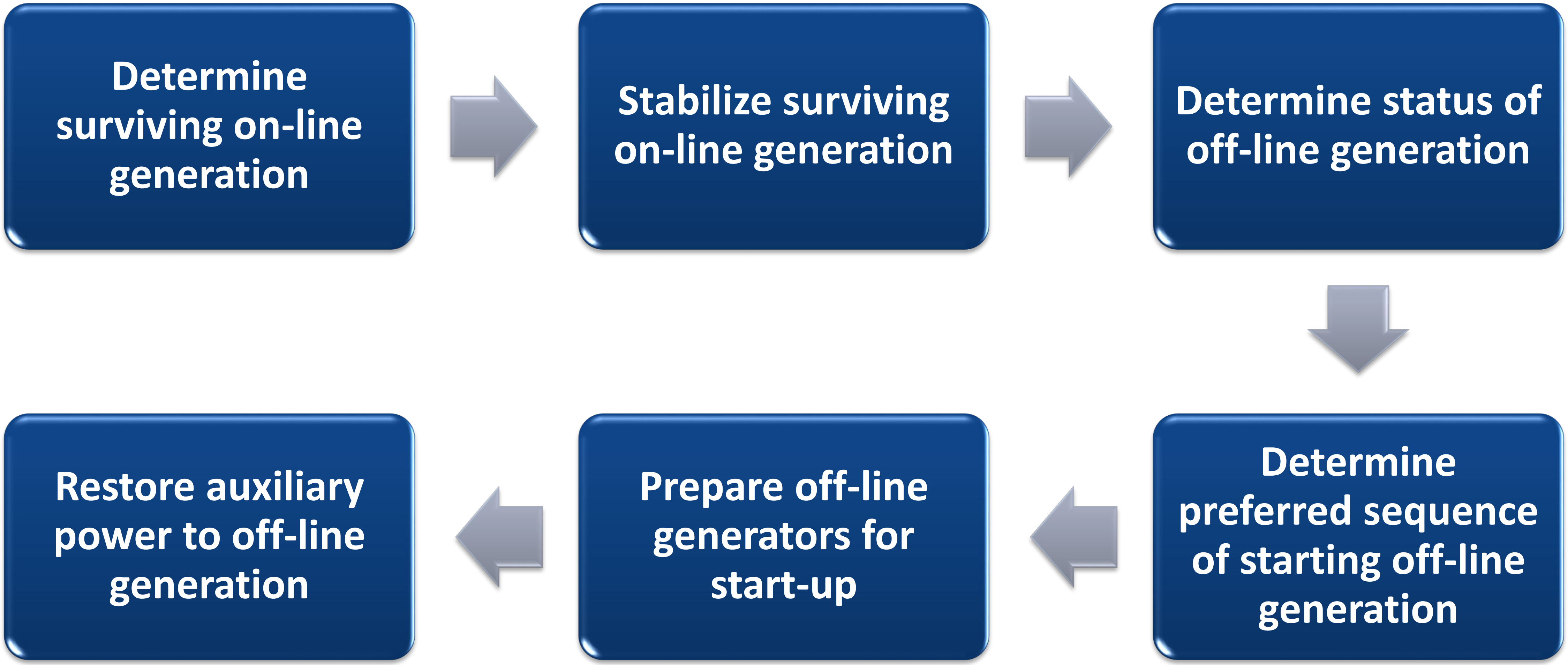
Hourly Generation Report

- This report is submitted every hour during the restoration process to the Transmission Owner Operator, who, in turn, will submit it to PJM
- Information includes:
  - Generation Report
    - Capacity and energy on line
    - Number of generators on line
    - Number of subsystems (islands)
  - Load Restoration Report
    - Total customer load restored
    - Number of customers restored
    - % Customers restored
    - % Customers restored last hour

Hourly Generation Report

- Information includes:
  - Capacity Due In:
    - Generation in one hour
    - Generation in three hours
    - Generation in six hours
  - Units On-line Since Last Report
  - Units Expected During Next Hour
  - Damage Detected Since Last Report
  - Cranking Power

Determining Generator Status



Determining Generator Status

- For generation that is still <u>on-line</u> determine:
  - Location
  - Damage
  - Stability
    - Frequency of island
    - Can load be added
  - Unloaded capacity
  - Connectivity to the rest of the system
    - Islanded
    - Part of Eastern Interconnection

Determining Generator Status

- For generation <u>off-line</u> determine:
  - Status prior to blackout (running, hot, on maintenance)
  - Blackstart capability of unit
  - Type of unit
    - Individual unit characteristics
  - Damage assessment
  - On-site source of power available or is off-site source (cranking power) required
  - Availability and location of cranking power

Determining Generator Status

- Sequence of restoration of off-line generation will be determined by:
  - Type of generator
    - Hydro: Can be started quickly without outside source
    - CT-small CTs: Can be started quickly (10 minutes); large CTs will take longer (up to 1 hour)
    - Drum-Type Steam: 1-20 away hours depending on status
    - Super Critical Steam: 4-20 away hours depending on status
    - Nuclear: At least 24 hours away (probably 48 hours or longer)
  - State of operation of unit prior to blackout
    - Hot units may be returned quicker than cold units
  - Unit availability

Determining Generator Status

- Auxiliary power should be restored to generation stations as soon as possible
- Short delays in restoring auxiliary power could result in long delays in restoring generation due to:
  - Congealed fuel oil
  - Sludge thickening in scrubbers (large demand of auxiliary power; as much as 30 MW)
  - Battery life expended
  - Bearing damage
  - Bowed shaft due to loss of turning gear

Determining Generator Status

- Prioritization of available cranking power to off-line generation depends on:
  - NRC requirements (more on this later!)
  - Individual restoration plan
  - Start-up time of unit
  - Availability of on-site auxiliary power
  - Distance of cranking power from generation
- Effective communication with generating stations is essential in this process!

Determining Generator Status

- Generating plant operators take actions to perform a safe plant shutdown
- Steam plant operators implement start-up procedures immediately following a plant shutdown unless instructed otherwise by the dispatcher
- Governors must be in service to respond to large frequency deviations
- Frequency control is maintained between 59.75 Hz and 61.0 Hz
- Plant operators must take action on their own to control frequency outside the range of 59.5 Hz - 61.0 Hz

Communications

- Communication between the TO and the generating units is critical as the restoration progresses
- PJM policy is that – during a system restoration – Transmission Owners will direct the loading of all generation within their footprint
  - This includes both Black Start and conventional units
  - IPP units may participate when available, and to the extend their contracts permit

Communications

- Generating plant personnel should be aware of certain evolutions, because of the potential effects on the generator, and the need for the generator operator to take controlling actions
  - Picking up significant blocks of load
  - Energizing long transmission lines, and the resulting voltage swings
- Once PJM resumes control of an island, they will direct the operation and output of units

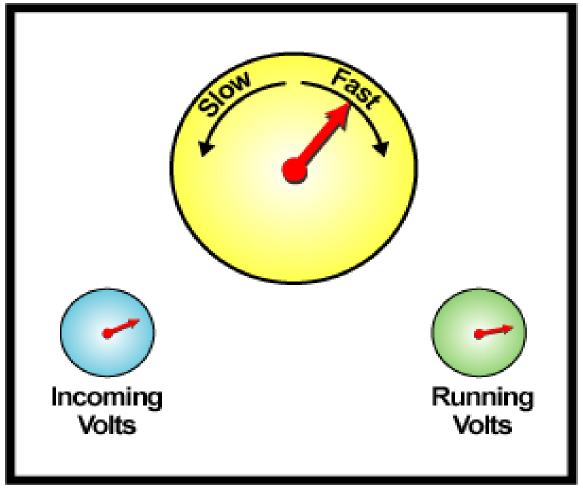
Generator Synchronizing

- In order to synchronize properly, three different variables must be monitored:
  - Voltage magnitudes
  - Frequency of the voltages
  - Phase angle difference between the voltages
- If voltage magnitudes are not matched, Mvar will rise suddenly when the breaker is closed
- If frequencies are not matched, a sudden change in MW flow will occur when the breaker is closed
- Most important, if phase angle difference is not minimized, MW flow will increase when the breaker is closed

Generator Synchronizing

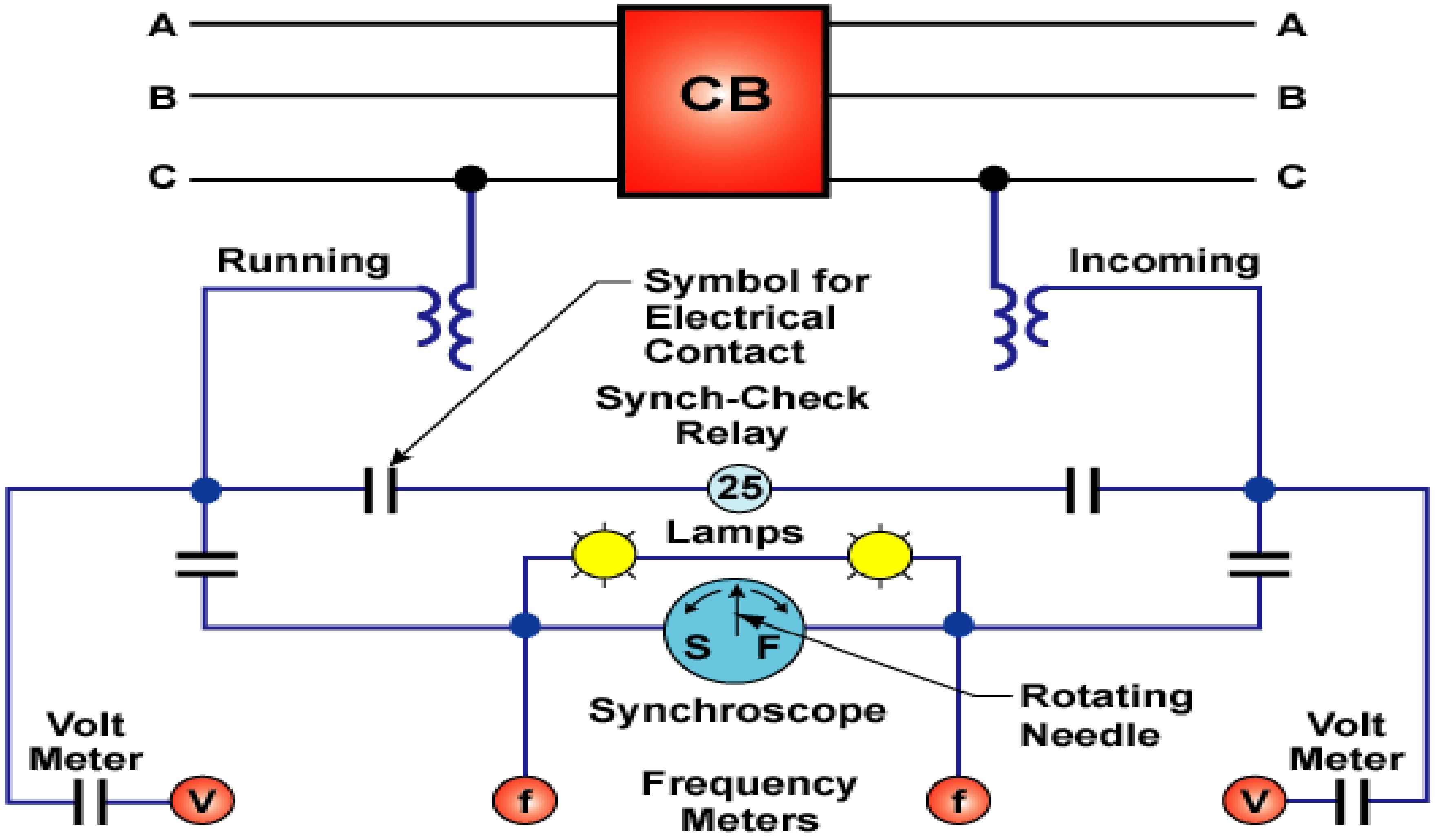
- System is modeled as an infinite bus
- With the unit output breakers open, the generator is operated at slightly above system frequency
- Excitation is adjusted for equal voltage magnitudes on either side of the output breakers
- The phase angle difference between the unit and system is monitored through the use of a synchroscope
- When the phase angle is small and heading towards zero in a clockwise direction, the output breakers are closed pulling the generator in step with the system

Generator Synchronizing



Generator Synchronizing

Voltage
Frequency
Phase Angle



Generator Synchronizing

- Reference (Running) voltage: Bus voltage
- Incoming voltage: Generator voltage
- Clockwise motion: Generator frequency is greater than bus frequency
- Once synchronized, excitation system can be put into automatic voltage regulation, and speed governor can be put in automatic generation control
- Synchro-check relay
  - Measures voltage on each side of breaker
  - Set for angular difference (~20 degrees) with timer
  - Will only prevent closure if out of synchronism

Bismarck Sync Demo

Island Interconnection

- Synchronization
  - Restoration of an interconnected system is defined as re-establishing electrical ties between generators in two or more areas, or subsystems, within a single TO, or between two or more TO's or systems, by synchronizing the areas to a common speed or frequency
    - Increased inertia tends to dampen fluctuations in frequency
    - Increases the capability to pick up larger blocks of load
    - Establishes or maintains Dynamic and Synchronous Reserves
    - Allows for supply of cranking power or energy for generation and load among the connected areas
    - Additional AGC control and regulation

Island Interconnection

- Synchronization
  - Islands cannot be connected unless they are in synchronism
    - Frequencies of islands must match
    - Voltage magnitudes and phase angles must match
    - Frequency and voltage of the smaller island should be adjusted to match the frequency and voltage of larger island
    - Frequency and voltage in a smaller system are able to be moved more easily with smaller generation shifts
  - Failure to match frequency and voltage between the two areas can result in significant equipment damage and possible shut-down of one or both areas

Island Interconnection

- Synchronization
  - Synchro-check relay
    - Measures voltage on each side of breaker
    - Set for angular difference (~20 degrees) with timer
    - Will only prevent closure if out of synchronism
      - Will not synchronize!
  - Synchroscope
    - Permits manual closing of breaker when two systems are in sync

Island Interconnection

- Islanded systems must be stable before attempting to interconnect with another company
  - PJM Interconnection Checklist is designed to ensure this (more later)
- Interconnection of a small stable island with a small unstable island will most likely result in a larger, but still unstable area
- If island is connecting to Eastern Interconnection, synchronism is still required, but stability issues are less of a concern

Island Interconnection

- How do I know if my system is stable?
  - Voltage within limits
  - Small voltage deviations when restoring load or transmission
  - Frequency within 59.75 and 61.0
  - Small frequency deviations when restoring load
  - Adequate reserves (synchronous and dynamic)
  - Significant amount of U/F relayed load picked up

Interconnection of TOs

PJM Actions:

- Act as coordinator and disseminator of information relative to generation and transmission availability
- Keep Member Companies apprised of developing system conditions
- Provide updated hydro capability
- Direct the restoration of the EHV system
- Direct synchronizing of islands in the RTO
- Coordinate with neighboring RCs and TOPs to establish external interconnections and establish tie schedules

Interconnection of TOs

Member Company Actions:

- Adjust frequency and voltage to as close as possible at synchronization point
- Regulation = 2% of system load
- Use synchronous reserve (including load shed) to keep frequency above 59.5 Hz
  - Shed 6-10 % of load for 1 Hz

Post-synchronism

- TOs/GOs continue to maintain communications with PJM to provide updated status of system conditions, in addition to the hourly report

Island Interconnection

Expectations of Interconnected Island

- Cranking power should be supplied to requesting companies as a priority to restoring native load
- Companies/areas that have restored all native load (or never lost it) are expected to consider supplying both cranking power and energy for load to requesting system
  - Up to normal operating limits
  - As long as security of supplying company is not compromised

Member Interconnection

Member Actions:

- Prior to synchronizing, each TO must ascertain that adequate reserves are available to cover the largest contingency within the interconnected area
  - Frequency of the smaller area is adjusted to match the frequency of the larger area
  - Area voltages and frequencies are controlled as close as possible prior to synchronization
  - Phase angle deviation of the voltages are as close to zero as possible
- TOs may share reserves and agree on a plan to act in a coordinated manner to respond to area emergencies

Member Interconnection

Member Actions:

- Identification of the coordinating TO controlling Flat-Frequency control and,

19	Which company will control frequency?	

- Identification of the TO controlling Flat Tie-Line control

20	Which company will control tie-line flow?	

- During a restoration process, does your company have the capability to control either Flat Frequency, or Flat Tie Line?

Member Interconnection

Member Actions:

- Frequency is maintained between 59.75 Hz and 61.0 Hz, adjusting it slightly above 60 Hz prior to picking up load
- Synchronous Reserve and manual load dump is used to keep frequency above 60 Hz
  - 6-10% load shed to restore frequency 1.0 Hz
- Dynamic Reserve is allocated/assigned proportionally to the available Dynamic Reserve in each area

Member Interconnection

Member Actions:

- After synchronization, the TOs continue to strengthen and stabilize the interconnected area by the closure of additional TO-to-TO tie lines
- As additional areas are added to the interconnected area, reserve assignments and regulation shall be recalculated and reassigned
- TOs/GOs continue to maintain communications with PJM to provide updated status of system conditions, in addition to the hourly report

Interconnection Checklist

INTERCONNECTION CHECKLIST			
DATE:		TIME:	
ISLAND "A":		ISLAND "B":	
CONTACT:		CONTACT:	

INFORMATION EXCHANGE

		ISLAND "A"		ISLAND "B"	
1	Are you currently interconnected?	YES	NO	YES	NO
2	If YES, which company (ies)				
3	Existing Tie-line schedules				
	FROM: TO:		MW		MW
	FROM: TO:		MW		MW
	FROM: TO:		MW		MW
4	Do you need start-up power?	YES	NO	YES	NO
4a	If YES, how much?		MW		MW
5	Can you supply energy?	YES	NO	YES	NO
5a	If YES, how much?		MW		MW

LOAD INFORMATION

		ISLAND "A"		ISLAND "B"	
6	Load Restored		MW		MW
6a	% of Load Restored		%		%
7	Load Restored With Underfrequency Relaying Enabled:	Hz	MW	Hz	MW
		Hz	MW	Hz	MW
		Hz	MW	Hz	MW
		Hz	MW	Hz	MW
7a	*Total Load Restored w/ Underfrequency Relaying In-Service*		MW		MW

CAPACITY / ENERGY INFORMATION

		ISLAND "A"		ISLAND "B"	
8	Largest Engery Contingency		MW		MW
9	Generation On-line: *Total Capacity*		MW		MW
10	Generation On-line: *Energy*		MW		MW
11	Synchronous (Spinning) Reserve (Not including Load Shedding):		MW		MW
12	Governor Reserve:		MW		MW
13	Total Dynamic Reserve: (Governor Reserve + Total Restored Underfrequency Relaying) (Row 7a + 12) (N/A if company is tied to the Eastern Interconnection)		MW		MW
14	Frequency Range over the Last Hour: (N/A if company is tied to the Eastern Interconnection)	-	Hz	-	Hz

TIE-LINE LOCATION AND SCHEDULING INFORMATION

		ISLAND "A"		ISLAND "B"	
15	Tie-line to be established:				
16	Tie-line schedule to be established:				MW
17	Which company will coordinate synchronization?				
18	Which breaker / substation will be used for synchronization?				
19	Which company will control frequency?				
20	Which company will control tie-line flow?				
21	Voltage At Boundary Buses:		kV		kV
22	Relay or SPS concerns @ sync locations?				

SYNCHRONIZATION

		ISLAND "A"		ISLAND "B"	
23	What time will synchronization occur?				
23a	Contact name:				
23b	Phone #:				
24	What is maximum amount of load pick-up without notification?		MW		MW
25	Conditions that would cause the opening of the tie-line:				

ADDITIONAL

Member Interconnection Scenarios

1. Member Company Transmission Owner connecting to another Member Company Transmission Owner within the RTO

2. Member Company Transmission Owner connecting with an external entity:
   - Islanded TO connecting to Eastern Interconnection

3. Cross Zonal Coordination:
   - Black Start of one zone supplying critical load of adjacent zone

(1) Interconnection Checklist (TO to TO)

INTERCONNECTION CHECKLIST

DATE:		**TIME:**	
ISLAND "A":		**ISLAND "B":**	
CONTACT:		**CONTACT:**	

INFORMATION EXCHANGE

			ISLAND "A"	ISLAND "B"
1	Are you currently interconnected?		YES ☐ Check NO ☐ Check	YES ☐ Check NO ☐ Check
2	If YES, which company (ies):			
3	Existing Tie-line schedules			
	FROM:	TO:	MW	MW
	FROM:	TO:	MW	MW
	FROM:	TO:	MW	MW
4	Do you need start-up power?		YES ☐ Check NO ☐ Check	YES ☐ Check NO ☐ Check
4a	If YES, how much?		MW	MW
5	Can you supply energy?		YES ☐ Check NO ☐ Check	YES ☐ Check NO ☐ Check
5a	If YES, how much?		MW	MW

LOAD INFORMATION

		ISLAND "A"		ISLAND "B"	
6	Load Restored		MW		MW
6a	% of Load Restored		%		%
7	Load Restored With Underfrequency Relaying Enabled:	Hz	MW	Hz	MW
		Hz	MW	Hz	MW
		Hz	MW	Hz	MW
		Hz	MW	Hz	MW
7a	*Total Load Restored w/ Underfrequency Relaying In-Service*		MW		MW

(1) Interconnection Checklist (TO to TO)

	CAPACITY / ENERGY INFORMATION				
8	Largest Engery Contingency		MW		MW
9	Generation On-line: ***Total Capacity***		MW		MW
10	Generation On-line: ***Energy***		MW		MW
11	Synchronous (Spinning) Reserve (Not including Load Shedding):		MW		MW
12	Governor Reserve:		MW		MW
13	Total Dynamic Reserve: (Governor Reserve + Total Restored Underfrequency Relaying) (Row 7a + 12) (N/A if company is tied to the Eastern Interconnection)		MW		MW
14	Frequency Range over the Last Hour: (N/A if company is tied to the Eastern Interconnection)	-N36	Hz	-	Hz
	TIE-LINE LOCATION AND SCHEDULING INFORMATION				
15	Tie-line to be established:				
16	Tie-line schedule to be established:				MW
17	Which company will coordinate synchronization?				
18	Which breaker / substation will be used for synchronization?				
19	Which company will control frequency?				
20	Which company will control tie-line flow?				
21	Voltage At Boundary Buses:		kV		kV
22	Relay or SPS concerns @ sync locations?				
	SYNCHRONIZATION				
23	What time will synchronization occur?				
	23a Contact name:				
	23b Phone #:				
24	What is maximum amount of load pick-up without notification?		MW	10	MW
25	Conditions that would cause the opening of the tie-line:				

(2) Interconnection Checklist (TO to Eastern Interconnection)

INTERCONNECTION CHECKLIST			
DATE:		TIME:	
ISLAND "A":		ISLAND "B":	
CONTACT:		CONTACT:	

INFORMATION EXCHANGE

		ISLAND "A"	ISLAND "B"
1	Are you currently interconnected?	YES ☐ Check NO ☐ Check	YES ☐ Check NO ☐ Check
2	If YES, which company (ies):		
3	Existing Tie-line schedules		
	FROM: TO:	MW	MW
	FROM: TO:	MW	MW
	FROM: TO:	MW	MW
4	Do you need start-up power?	YES ☐ Check NO ☐ Check	YES ☐ Check NO ☐ Check
4a	If YES, how much?	MW	MW
5	Can you supply energy?	YES ☐ Check NO ☐ Check	YES ☐ Check NO ☐ Check
5a	If YES, how much?	MW	MW

LOAD INFORMATION

		ISLAND "A"	ISLAND "B"
6	Load Restored	MW	MW
6a	% of Load Restored	%	%
7	Load Restored With Underfrequency Relaying Enabled:	Hz MW	Hz MW
		Hz MW	Hz MW
		Hz MW	Hz MW
		Hz MW	Hz MW
7a	*Total Load Restored w/ Underfrequency Relaying In-Service*	MW	MW

(2) Interconnection Checklist (TO to Eastern Interconnection)

	CAPACITY / ENERGY INFORMATION							
8	Largest Engery Contingency			MW				MW
9	Generation On-line: ***Total Capacity***			MW				MW
10	Generation On-line: ***Energy***			MW				MW
11	Synchronous (Spinning) Reserve (Not including Load Shedding):			MW				MW
12	Governor Reserve:			MW				MW
13	Total Dynamic Reserve: (Governor Reserve + Total Restored Underfrequency Relaying) (Row 7a + 12) (N/A if company is tied to the Eastern Interconnection)			MW				MW
14	Frequency Range over the Last Hour: (N/A if company is tied to the Eastern Interconnection)	-N36		Hz		-		Hz
	TIE-LINE LOCATION AND SCHEDULING INFORMATION							
15	Tie-line to be established:							
16	Tie-line schedule to be established:							MW
17	Which company will coordinate synchronization?							
18	Which breaker / substation will be used for synchronization?							
19	Which company will control frequency?							
20	Which company will control tie-line flow?							
21	Voltage At Boundary Buses:			kV				kV
22	Relay or SPS concerns @ sync locations?							
	SYNCHRONIZATION							
23	What time will synchronization occur?							
	23a Contact name:							
	23b Phone #:							
24	What is maximum amount of load pick-up without notification?			MW			10	MW
25	Conditions that would cause the opening of the tie-line:							

(3) Interconnection Checklist (Cross Zonal Coordination)

INTERCONNECTION CHECKLIST							
DATE:				TIME:			
ISLAND "A":				ISLAND "B":			
CONTACT:				CONTACT:			

INFORMATION EXCHANGE

				ISLAND "A"		ISLAND "B"	
1	Are you currently interconnected?			YES ☐ Check	NO ☐ Check	YES ☐ Check	NO ☐ Check
2	If YES, which company (ies):						
3	Existing Tie-line schedules						
	FROM:	TO:			MW		MW
	FROM:	TO:			MW		MW
	FROM:	TO:			MW		MW
4	Do you need start-up power?			YES ☐ Check	NO ☐ Check	YES ☐ Check	NO ☐ Check
	4a	If YES, how much?			MW		MW
5	Can you supply energy?			YES ☐ Check	NO ☐ Check	YES ☐ Check	NO ☐ Check
	5a	If YES, how much?			MW		MW

LOAD INFORMATION

6	Load Restored			MW		MW
	6a	% of Load Restored		%		%
7	Load Restored With Underfrequency Relaying Enabled:		Hz	MW	Hz	MW
			Hz	MW	Hz	MW
			Hz	MW	Hz	MW
			Hz	MW	Hz	MW
	7a	*Total Load Restored w/ Underfrequency Relaying In-Service*		MW		MW

(3) Interconnection Checklist (Cross Zonal Coordination)

	CAPACITY / ENERGY INFORMATION				
8	Largest Engery Contingency		MW		MW
9	Generation On-line: ***Total Capacity***		MW		MW
10	Generation On-line: ***Energy***		MW		MW
11	Synchronous (Spinning) Reserve (Not including Load Shedding):		MW		MW
12	Governor Reserve:		MW		MW
13	Total Dynamic Reserve: (Governor Reserve + Total Restored Underfrequency Relaying) (Row 7a + 12) (N/A if company is tied to the Eastern Interconnection)		MW		MW
14	Frequency Range over the Last Hour: (N/A if company is tied to the Eastern Interconnection)	-N36	Hz	-	Hz
	TIE-LINE LOCATION AND SCHEDULING INFORMATION				
15	Tie-line to be established:				
16	Tie-line schedule to be established:				MW
17	Which company will coordinate synchronization?				
18	Which breaker / substation will be used for synchronization?				
19	Which company will control frequency?				
20	Which company will control tie-line flow?				
21	Voltage At Boundary Buses:		kV		kV
22	Relay or SPS concerns @ sync locations?				
	SYNCHRONIZATION				
23	What time will synchronization occur?				
	23a Contact name:				
	23b Phone #:				
24	What is maximum amount of load pick-up without notification?		MW	10	MW
25	Conditions that would cause the opening of the tie-line:				

Reserve Requirements

- Synchronized and Dynamic Reserves are the only reserve monitored during a system restoration
  - Synchronized reserves should be sufficient to cover the largest energy contingency in each island
    - Can be made up of generation that can be manually increased or;
    - Load that can be manually shed in within 10 minutes
  - Dynamic reserves should be sufficient to cover the largest energy contingency in each island
    - Comprised of governor reserve on units and load equipped with under-frequency load shed relays

PJM Assumes Control

- PJM assumes control of an area when:
  - Control of the area becomes too burdensome for any one TO
  - PJM desires to assume control to facilitate EHV restoration or establish tie lines with adjacent system
  - Requested by a Member
- PJM needs accurate system status information prior to assuming control of the restoration!

PJM Assumes Control

Date:	Time:
Reporting Company:	
Regulation MW	Synchronous Reserve MW
Frequency Controlled by:	Frequency Maintained From to HZ

Dynamic Reserves:

Underfrequency Relays:

Percent at 59.5 HZ_____% Percent at 59.3 HZ_____% Percent at 59.1 HZ_____%
Percent at 59.0 HZ_____% Percent at 58.9 HZ_____% Percent at 58.7 HZ_____%
Percent at 58.5 HZ

Governor Response:

Steam MW CT's MW Hydro MW

Load Pick - up Factors: Steam Units **5%** CT's **25%** Hydro Units **15%**

Total Load with Underfrequency Relaying __________MW
Total Governor Response: __________MW
Total Dynamic Reserves: MW

INTERCHANGE SCHEDULES (Company To Company, Company To Outside)

From Co.	To Co.	MW	From Co.	To Co.	MW

Connected Load	
765 kV MW of Connected Load MW	
500 kV MW of Connected Load MW	
345 kV MW of Connected Load MW	
230 kV MW of Connected Load MW	

Comments:
____
____
____
____
____
____

6553

Exhibit 17: PJM Assumes Control

PJM Assumes Control

PJM Actions:

- Assimilates required information on reporting form
- Determines required Dynamic and Synchronous reserve for area based on largest contingency
  - Assign reserve proportional to capacity
- Determine regulation requirement
  - 2% of interconnected area load
  - Assign regulation proportional to connected load
- Coordinate hydro operations
- Updates the DMT to reflect unit capability as reported by the GOs

PJM Assumes Control

Member Actions:

- Continue returning generation and load to maintain frequency
- Report returning units to PJM dispatcher
- Respond to emergency procedures as initiated by PJM
- Maintain established tie scheduled with other TOs until PJM returns to free-flowing tie conditions
  - Coordinate with PJM any change to pre-existing schedules (internal or external)
- Maintain communications with PJM to provide an updated status of system conditions, in addition to the hourly report

PJM Assumes Control

Member Actions:

- TO requests PJM approval prior to the closure of any reportable transmission line or a line that establishes an interconnection to an external system
- The TOs assure that adequate underlying transmission capability is electrically connected at the interconnection point of the 500 kV and above bulk transmission system to provide adequate fault current (relay protection) and VAR absorption capability when the line is energized (overvoltage)
- TO's/GO's continue to return generating units to on-line status and restore native load in small increments to maintain generation and load balance

Resources & References

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NERC. (2012). *Arizona-Southern California Outages on September 8, 2011.* Retrieved from http://www.nerc.com/pa/rrm/ea/September%202011%20Southwest%20Blackout%20Event%20Document%20L/AZOutage_Report_01MAY12.pdf

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Ohno,T. & Imai, S. (2006). *The 1987 Tokyo Blackout*. Available from https://ieeexplore.ieee.org/iel5/4075697/4075698/04075764.pdf

Resources & References

PJM. (2018). *PJM Manual 36: System Restoration* (rev. 25). Retrieved from https://www.pjm.com/~/media/documents/manuals/m36.ashx

Questions?

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Member Community

The Member Community is PJM's self-service portal for members to search for answers to their questions or to track and/or open cases with Client Management & Services